COGENERATION

ALTERNATIVE ENERGY

PROCEEDINGS

Ministry of Energy
Robert C. Wong, Minister
Ontario

Cogeneration:
Experience and Prospects in Ontario
Proceedings of the
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Seminar

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Opening Remarks Cogeneration : Experience and Prospects in Ontario

By

Donald A. Crosbie

Ontario Ministry of Energy

REMARKS BY

DONALD A. CROSBIE
DEPUTY MINISTER
ONTARIO MINISTRY OF ENERGY

AT

COGENERATION: EXPERIENCE
AND PROSPECTS IN ONTARIO:

CARA INN, MISSISSAUGA, ONTARIO
THURSDAY, MARCH 10, 1988
9:00 A.M.

CHECK AGAINST DELIVERY

Good morning, ladies and gentlemen.

I want to welcome you to today's seminar, which is jointly sponsored by the Ontario Ministry of Energy, the Ontario Natural Gas Association, and the Consulting Engineers of Ontario.

We have a very full -- and I think a very interesting program for you. I plan to take just a few minutes to explain the government's interest in cogeneration and other forms of parallel generation technology.

But first, I'll give you a personal observation about my first reaction to cogeneration.

I came to the Ministry of Energy five months ago, via the Ministry of Consumer and Commercial Relations and several other ministries.

Consumer and Commercial, as you may know, has a Film Review Board -- which is responsible for approving the content of all movies and videos shown in Ontario.

After all those hours watching "The Tin Drum" and "Last Tango in Paris" -- I thought cogeneration was probably something the censor usually cuts out.

In fact, I was completely wrong. It turns out the government wants to see more cogeneration, not less.

There are many good reasons for cogeneration's increasing popularity. From the government's point of view, the most important one is that cogeneration can help improve Ontario's industrial competitiveness.

Today, Ontario and Canada lag far behind most other developed areas in energy efficiency. Other countries can now produce goods that are every bit as good as ours. But one of their major advantages is that they use a lot less energy to do it.

Right now, the energy efficiency gap between us and the competition is at least 30 per cent -- and growing larger. So long as this continues, it will hurt Ontario's ability to compete in international markets.

We depend on those markets for thousands of jobs, and for our enviable standard of living. And we cannot afford to ignore the fact that those markets are changing very quickly, all around the world.

One of the key changes is a worldwide move to greater energy efficiency and productivity. Ontario must ride the crest of the efficiency wave -- or we will wallow in the trough.

Energy developments at the federal level have also been changing rapidly in recent years. The federal government is committed to deregulating oil and gas markets, and to implementing a Free Trade Agreement with the United States.

Deregulation will open up many doors, including direct purchases and competitive marketing programs for natural gas. The Free Trade Agreement, if it is implemented, will also make energy markets in North America even more competitive.

Keeping pace with those changes represents an enormous challenge for all of us -- private sector and government alike. The Ontario government can only do so much. But that being said, I can tell you that we are committed to doing as much as we can.

We have already cut our energy costs way down since 1975. And we are planning to reduce energy consumption by a further 10 per cent by 1992. In the years ahead, government buildings and vehicles will meet tough new standards for energy efficiency.

Setting an example is important, and so is providing leadership. The Government of Ontario will do both.

Another major role for government is to provide encouragement and support for energy conservation and efficiency outside government -- right across the spectrum of Ontario society.

I want to make it clear that we are not supporting energy efficiency and conservation because it's some kind of moral crusade. The economics of energy efficiency speak for themselves.

Every year, Ontario spends $13-billion on energy -- and that's wholesale. A 20 per cent efficiency improvement translates into savings of three to four billion a year. That extra cash would do a lot for our economy.

But the benefits of efficiency go farther than giving us extra money in the bank. Conservation and efficiency will also give us

- more competitive industries;
- lower operating costs for public institutions;
- local investment and job creation; and
- a cleaner environment.

The government is committed to ensuring that we realize these benefits, by bringing about a more efficient Ontario.

Ontario is Canada's largest energy market. That situation will continue, even after we achieve major efficiency gains. Unlike other provinces, however, Ontario's only major indigenous energy is electricity.

To put our own energy house in order, we have to improve the efficiency with which we use electricity -- both in the home, and in the plant.

Electricity demand is forecast to grow by about 2.5 per cent per year until the year 2000. Since the recession, demand growth has averaged about 4.5 per cent per year. Major new sources of supply to meet this demand are expensive and controversial.

Today, nuclear, coal and hydro plants provide most of our electricity. In the years ahead, the government would like to see a more diverse mix of sources.

So: The search is on for efficient, competitive alternatives -- technologies that can make the grade in a rapidly-changing energy market, and in a world which is placing a much higher premium on productivity.

Fortunately, parallel generation technologies can help us accomplish all those objectives.

The ministry estimates that parallel generation's potential in Ontario is about 1,600 megawatts by the turn of the century. Cogeneration accounts for more than 1,000 megawatts of that.

Now, a thousand megawatts may not seem like much -- especially when you compare it to the output of a nuclear station like Darlington, or even a coal-fired plant like Nanticoke, which can produce up to 4,000 megawatts when all eight units are fired up.

But when you start to look at the environmental and other costs of running a station like Nanticoke at maximum capacity, parallel generation starts to look a lot more attractive.

And it looks good from just about everybody's perspective -- the private producer, Ontario Hydro, and the government.

Cogeneration can be a clean, efficient alternative. It takes advantage of a proven technology, where the costs and paybacks are well-known.

Unlike large, conventional generating stations, cogeneration plants are not megaprojects. They can be built all across the province, often as an add-on to existing plants, and they can be tied into transmission lines. It should also be noted that the economic activity they create is spread out more evenly across the province.

Over the past few years, the Ministry of Energy has introduced encouragement programs for other parallel generation technologies -- for small hydraulics, energy from municipal waste, and energy from wood waste. Now we are developing a formal parallel generation policy.

We have not yet introduced an encouragement program aimed specifically at cogeneration. But we are helping some Ontario companies with the costs of assessing the potential for cogeneration in specific operations.

Our work so far includes a broad market assessment for cogeneration, and more detailed assessments of a major hotel, a greenhouse and a packaging plant. If these pilot project activities prove to be useful, we will be considering more focused assistance, to explore opportunities for other cogeneration plants.

The bottom line, though, is that we want to assist the private sector in looking at the cogeneration option. Because we believe that cogeneration can be economically attractive to Ontario business, major capital support from government probably isn't necessary.

From an energy producer's point of view, the economics of cogeneration can be excellent. There is a large market for cogenerated power, and a respectable return on investment.

Last year, Ontario Hydro increased the rates it pays for privately-generated electricity. More recently, Hydro has made available up to $250-million over the next four years for demand reduction programs, including electricity conservation and industrial cogeneration.

These two initiatives alone have helped to make cogeneration much more attractive. For Ontario Hydro, cogeneration can provide useful electrical capacity at a very attractive cost. And that is one of the reasons the corporation shares our enthusiasm for this promising technology.

Substantial economic benefits and major improvements in operational efficiency are strong incentives for Ontario businesses to explore cogeneration opportunities.

We have invited you here today to help you learn more about what cogeneration has to offer. We have lined up expert speakers who will address each of the areas I have mentioned.

You'll spend the morning hearing about the latest developments in cogeneration technology -- from people who know what it can do.

This afternoon, you'll hear from people who have practical experience with cogeneration -- from a variety of points of view.

You will also hear from some experts on the regulatory side -- about Hydro rates and interconnections, and the kind of gas contracts and prices you can expect in today's market.

As I said, it's a full program. I also hope it will be an interesting and profitable day for you all.

Thank you.

An Overview of
Cogeneration Market Opportunities

By
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2

AN OVERVIEW OF
COGENERATION MARKET OPPORTUNITIES

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For presentation on March 10, 1988

at the Seminar on

Cogeneration Experience and Prospects in Ontario

Toronto, Canada

Sponsored by the

Ontario Ministry of Energy

AN OVERVIEW OF COGENERATION MARKET OPPORTUNITIES

1 - INTRODUCTION

I am honored to be invited to share with you my thoughts on cogeneration market opportunities in Ontario. I am especially pleased that so many of the seminar speakers and delegates represent the technical and financial dimensions of cogeneration. Without these practical perspectives, no opportunities, however substantial, will be translated into project planning, design and implementation.

My primary objective is to discuss recent research on potential cogeneration markets in the industrial and buildings sectors. In this regard, I will plagiarize liberally from my work on Cogeneration Potential and Barriers to its Development, a study undertaken by Acres International Limited for the Ontario Ministry of Energy. My second objective is to address the issue of how cogeneration market opportunities may be realized. In particular, I will suggest ways in which the various interested parties could contribute to the mutually beneficial realization of these opportunities.

The paper is organized into five parts, as follows.

Following the introduction, part 2 sets the stage by defining the key terms relating to various types of market potential: technical, economic, financial and implementation. In part 3, I review the market segments and case studies on which the most recent estimates of potential were based. I also point out, as a by-product of this data base, the estimated theoretical or technical limits to cogeneration in each market category. Part 4 presents the approach and results of the assessment of market opportunities. A comparison of these results with several other estimates is also provided. Finally, in part 5, I will briefly discuss the roles various interested parties could play in promoting cost-effective cogeneration development in Ontario.

2 - DEFINITIONS OF MARKET POTENTIAL

The feasibility of a particular cogeneration project, and more broadly, the market potential or opportunities for cogeneration across a province or nation may be defined in four ways:

- technical
- economic
- financial
- implementation.

As shown in Exhibit 1, the four types of market opportunities become successively smaller as we move from technical to economic, financial and implementation categories of potential.

Technical market potential is defined as the cogeneration capacity (in MW) of all projects which could be designed using currently known technology.

Economic market potential is defined as the cogeneration capacity of all projects that meet the criteria of economic feasibility. In turn, economic feasibility is determined on the basis of whether or not a project is beneficial to the province or nation as a whole. A commonly used indicator of economic feasibility is the 'supply price' of cogenerated electricity.[1] It is calculated as the constant real (inflation-adjusted) dollar price per kW.h of electricity, required to meet project costs at a given real discount rate. This is computed simply

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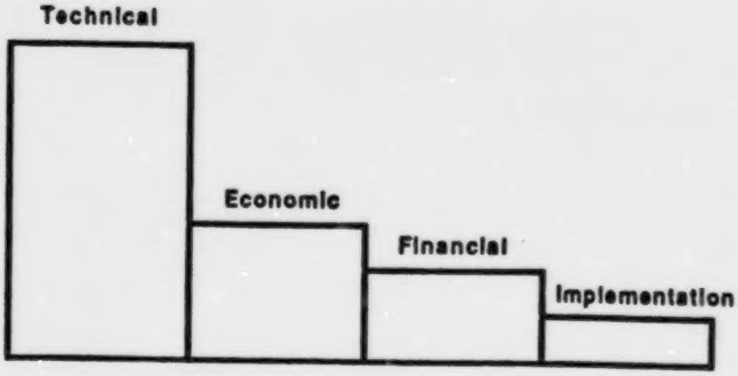
[1] Supply price is sometimes referred to as 'supply cost,' 'resource cost,' 'levelized production cost,' and 'shadow price.'

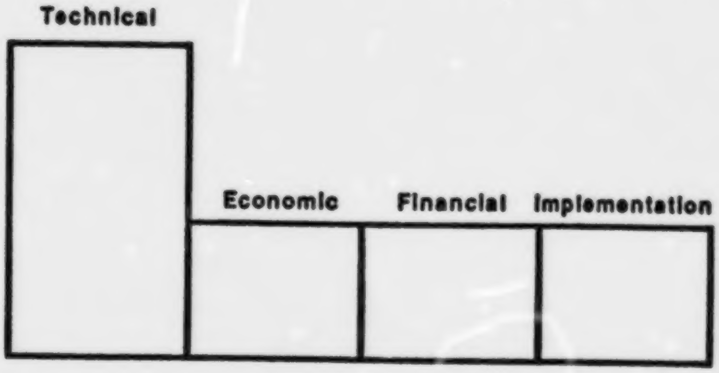
Exhibit 1

Hierarchy of Cogeneration Potentials

(A) Typical Situation (With Market Imperfections)



(B) Ideal Situation (Without Market Imperfections)



by dividing the present worth (PW) of investment plus operating costs by the PW of electrical energy supplied by the project. All costs are measured over the economic life of the project and exclude transfer payments such as taxes and subsidies. If a project provides electricity at a lower supply cost than that associated with conventional bulk generation, it is judged to be economically feasible.

Financial market potential is based on the perspective of the investment decision-maker and hence an economic project may or may not be financially feasible. In contrast to economic analysis, financial analysis includes all taxes and subsidies and uses current (escalated) dollars, private discount rates, and a planning horizon which may be different from the economic life of the project . Commonly used indicators of financial feasibility are the payback period and the return on total or equity investment. Financial potential is calculated as the sum of financially feasible projects.

Finally, implementation market potential is a more restrictive notion of financial potential. It takes into account the fact that not all financially feasible projects will be implemented. This may be due to such factors as financing problems, insufficient capital budgets or simply lack of information and/or interest.

The distinctions among the various types of market potential are of more than academic interest. They serve as a useful guide in forecasting cogeneration activity, setting targets, and designing policies to counteract imperfections in cogeneration markets. For example, a policy implication of this framework may be the need to narrow the gap between financial and implementation market potentials. More generally, those involved in market planning and marketing activities should consider the four types of market potentials as indicators of less certain longer term market opportunities (defined by technical and economic potentials) and more certain near-term opportunities (defined by financial and implementation potentials).

3 - COGENERATION MARKET CATEGORIES AND CASE STUDIES

Exhibit 2 illustrates the market categories developed in a recent study of cogeneration potential. Note that it is a 2-dimensional framework identifying four end-use sectors (industry, institutional, commercial and residential) and three heat demand categories (low, medium and high). Based on boiler registration data, floor space inventories and energy end-use studies, heat demands were estimated for each cell in the matrix. The technical potential for cogeneration was then estimated by selecting particular cogeneration technologies and appropriate power-to-heat ratios for each market segment. Of the total technical potential of about 10 000 MW, the industrial sector is shown to contribute 38%, institutional buildings 5%, commercial buildings 18% and apartment buildings 39%.

Case study data were developed for the various market categories within this framework. As shown in Exhibit 3, a total of 66 case studies were utilized. The large number of industrial high heat demand cases stems from the availability of survey-based technical data developed for EMR in an earlier study.[1] The remaining cases were developed by Acres engineers based on data from actual installations and conceptual designs for representative situations. In all cases the technical parameters included the following.

- Choice of cogeneration technology and equipment capacity.
- Incremental capital cost (relative to a no-cogeneration energy system).
- Incremental nonenergy operating cost per year.
- Incremental fuel requirement per year.
- Cogenerated electrical energy production per year.
- Electrical energy consumption per year (to estimate the parallel generator's sale or purchase of electrical energy).

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[1] See Acres Shawinigan Limited, The Potential for Industrial Cogeneration in Canada, Toronto 1979.

EXHIBIT 2

FRAMEWORK FOR THE ESTIMATION OF MARKET POTENTIAL

	Heat Demand Category						
	Low		Medium		High		
	(< 25,000 #/hr)		(25,000-000,00 #/hr)		(> 100,000 #/hr)		Total
Sector and Subsector	Cogen System (MW)	Assoc Power	Cogen System (MW)	Assoc Power	Cogen System (MW)	Assoc Power	Assoc Power (MW)
Industrial:							
Pulp & Paper	STW	16	STW	32	STW	385	433
Iron & steel	GT	6	GT	18	GT	426	450
Smelting & ref	GT	13	GT	41	GT	156	210
Petroleum Prod	GT	4	GT	6	GT	575	585
Chemicals	GT	33	GT	95	GT	429	557
Other Mfg	GT	255	GT	403	GT	882	1,540
Total		327		595		2,853	3,775
Institutional:							
Universities	N/A	-	ST	59	STD	87	146
Hospitals	D	141	D	215	N/A	-	356
Total		141		274		87	502
Commercial:							
Shopping Malls	D	342	GT	307	N/A	-	649
Offices	D	682	D	455	N/A	-	1,137
Total		1,024		762			1,786
Residential:							
Apartments	D	3,902	N/A	-	N/A		3,902
TOTAL		5,394		1,631		2,940	9,965

Total Technical Potential: 9,965 MW

ST - Steam Turbine
STD - Steam Turbine with Supplemental Diesel
STW - Steam Turbine (with wood waste)
GT - Gas Turbine
D - Diesel
N/A - No technical potential indicated.

EXHIBIT 3

NUMBER AND TYPES OF CASE STUDIES

	Heat Demand Category			
	Low	Medium	High	Total
Industrial sector	1	1	58	60
Institutional Sector				
- Universities	-	1	1	2
- Hospitals	-	1	-	1
Commercial Sector				
- Large office buildings	-	1	-	1
- Shopping mall	-	1	-	1
Residential Sector				
- Large Apartment Buildings	1	-	-	1
Total	2	5	59	66

The analysis of economic, financial and implementation potentials was based on this technical foundation.

4 - ANALYSIS OF MARKET POTENTIALS

4.1 - Economic Potential

The economic analysis was designed to assess the cost competitiveness of cogenerated electricity vis-a-vis conventionally produced electrical energy. A 'public' perspective was adopted, as discussed earlier, to ensure that the economic limits to cogeneration would not be biased by market imperfections (such as short planning horizons) that surround the financial analysis of cogeneration projects. A project was considered cost competitive if its real (1985 dollar) supply price was less than or equal to the long-run levelized cost of conventional electricity supplies in Ontario, estimated at 4.5c/kW.h.

Economic parameters were developed as follows. The planning horizon was set at 25 years, the economic life of the cogeneration plant. The real discount rate was based on the Ministry's figure of 5%. This is a 'hard-nosed' assumption, as a higher rate would enhance the economic cost competitiveness of cogeneration relative to bulk power generation. (In comparison, note that federal government guidelines suggest rates of 7% and 10% and Ontario Hydro uses a 4% real discount rate.)

Turning to energy prices, the supply prices of natural gas and wood fuels were used to measure the economic costs of incremental fuel requirements--these were assumed to equal market prices in the study period. The market prices of natural gas were based on forecasts prepared by the Ministry of Energy. Wood waste was estimated to have a delivered market price equal to one-third of the natural gas price. Finally, note that buyback rates are not relevant to the supply price analysis as we are interested only in comparing the economic or 'bricks and mortar' costs of parallel versus bulk generation.

Two sets of results emerge from the analysis. The first is a summary of project-specific indicators while the second represents an extrapolation of case study results to provide sectoral and provincial estimates of economic market potential. Exhibit 4 shows a summary of the case study results. Perhaps the most striking feature of this summary is that, out of 16 market categories, 14 have average supply prices below the economic cost of bulk electricity generation.

Aggregating these results to the province as a whole shows a total economic market potential of about 3 800 MW, or 38% of the identified technical potential discussed earlier. Exhibit 5 provides the sectoral composition of this total potential. Key findings include the following:

(a) About 50% of the economic potential is in industry, with 34% in the apartments sector, 12% in office buildings and 3% in hospitals and universities.

(b) Within industry, the greatest economic potential is in the pulp and paper, chemicals and petroleum products industries (about 50% of the sectoral total).

(c) Within industry, the high heat demand category offers the greatest economic potential, accounting for 76% of the sectoral total. The medium heat category represents virtually the entire remaining potential.

EXHIBIT 4

AVERAGE SUPPLY PRICES BY CASE STUDY GROUP
(1985$/MW.h)

Subsector	Heat Demand Category Low	Medium	High
Pulp and paper	36	17	15
Iron and steel	-	-	23
Smelting and refining	-	-	25
Petroleum products	-	-	23
Chemicals	-	-	25
All other industrial	54	16	34
Universities	-	37	24
Hospitals	-	38	-
Large Shopping Malls	-	72	-
Office Buildings	-	41	-
Large apartment buildings	36	-	-

EXHIBIT 6

TOTAL COGENERATION POTENTIAL

(Base Case - Wood/Gas Fuel Option and Base Case Prices)

Sector Sub-Sector	Heat Demand Category	Total Economic Potential (MW)
Industrial		
- Pulp & Paper	Low	4.6
	Medium	8.2
	High	385.2
- Iron & Steel	High	177.9
- Mining & Smelting	High	57.1
- Petroleum Product	High	230.5
- Chemicals	High	262.6
- All Other	Low	0.0
	Medium	460.0
	High	356.3
Total Industrial		1942.3
Institutional		
- Universities	Medium	14.4
	High	18.0
- Hospitals	Medium	78.0
Total Institutional		110.4
Commercial		
- Shopping Malls	Medium	0.0
- Offices	Medium	459.0
Total Commercial		459.0
Residential		
- Apartments	Low	1321.5
Total Residential		1321.5
TOTAL ALL SECTORS		3833.2

4.2 - Financial and Implementation Potentials

In contrast to the economic evaluations, the analysis of financial and implementation potentials reflects the perspective of the investment decision-maker. The most common yardstick in this perspective is the simple (undiscounted pre-tax) payback period. A less common indicator is the discounted cash flow return on equity investment over the planning horizon of the project. This second indicator has two advantages: it does not ignore cash flows after the payback period, thus taking into account the time value of money, and it allows a ready comparison of yields relative to other productive and financial investment opportunities.

Nonetheless, in this paper the focus will be on the more widely used payback criterion. In the base case analysis, the financial market potential for cogeneration is based on projects whose payback period is 5 years or less. This corresponds to a minimum real pre-tax return on investment of about 20%. But financial feasibility is not a sufficient condition to ensure the implementation of cogeneration projects. Constraints exist to the realization of financially attractive opportunities. These include lack of information, an institutional reluctance to become a power generator, and perhaps as a reflection of these factors, the use of stringent payback criteria for cogeneration. Although no single criterion can fully measure the scope of the implementation potential, a more restrictive three-year payback period was used in the base case.[2]

Other features of the analysis included the following:

- Nominal (current) dollar costs used with real dollars escalated by the CPI.

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[2] Surveys carried out by EMR to pinpoint the criteria for implemented (as opposed to simply financially viable) conservation projects point to 3 years as the mnaximum payback period.

- Investment grants included from the base case, but considered in the sensitivity analysis.

- Energy prices also expressed in nominal terms and reflecting market prices throughout. Electricity prices are specified by end-use sector.

- Buyback rates are set at 3.45 cents/kW.h in 1986, escalating at the CPI over the study horizon.

As in the case of economic analysis, two sets of results were obtained. The first is a summary of project-specific payback periods as presented in Exhibit 6. Note that only the industrial and university sectors meet the required maximum payback period of 5 years.

The case study results were aggregated to provide province-wide estimates of market potential, as shown in Exhibit 7. The total financial and implementation potentials are about 1700 MW and 1400 MW, representing 44% and 35% of the economically justified potential. Other key findings include the following:

(a) Industry contributes 99% and 100% of the financial and implementation potentials, respectively. (It accounted for 'only' 38% of technical potential.)

(b) Within industry, three market segments (pulp and paper, chemicals, and petroleum products) account for over 50% of the sectoral potentials.

(c) Also within industry, 70% of the financial potential and 65% of the implementation potential stem from the high heat demand category.

EXHIBIT 6

AVERAGE PAYBACK PERIODS BY CASE STUDY GROUP
(years)

Subsector	Heat Demand Category Low	 Medium	 High
Pulp and paper	>10	3	3
Iron and steel	-	-	4
Smelting and refining	-	-	4
Petroleum products	-	-	3
Chemicals	-	-	4
All other industry	>10	2	8
Universities	-	>10	4
Hospitals	-	>10	-
Large Shopping Malls	-	>10	-
Office Buildings	-	>10	-
Apartment buildings	>10	-	-

EXHIBIT 7

TOTAL COGENERATION POTENTIAL

(Base Case - Wood/Gas Fuel Option and Base Case Prices)

Sector Sub-Sector	Heat Demand Category	---- Total Cogeneration Potential --- Economic (MW)	Financial (MW)	Implementation (MW)
Industrial				
- Pulp & Paper	Low	4.6	0.0	0.0
	Medium	8.2	8.2	0.0
	High	385.2	385.2	301.3
- Iron & Steel	High	177.9	160.2	105.6
- Mining & Smelting	High	57.1	37.4	37.4
- Petroleum Product	High	230.5	230.5	194.4
- Chemicals	High	262.6	244.4	217.8
- All Other	Low	0.0	0.0	0.0
	Medium	460.0	460.0	460.0
	High	356.3	133.0	30.1
Total Industrial		1942.3	1658.9	1346.7
Institutional				
- Universities	Medium	14.4	0.0	0.0
	High	18.0	18.0	0.0
- Hospitals	Medium	78.0	0.0	0.0
Total Institutional		110.4	18.0	0.0
Commercial				
- Shopping Malls	Medium	0.0	0.0	0.0
- Offices	Medium	459.0	0.0	0.0
Total Commercial		459.0	0.0	0.0
Residential				
- Apartments	Low	1321.5	0.0	0.0
Total Residential		1321.5	0.0	0.0
TOTAL ALL SECTORS		3833.2	1676.9	1346.7

(d) The only nonindustrial market segment with any financial potential is the university group. Nonindustrial subsectors as a whole account for 50% of the economic potential but less than 1% of the financial and implementation potentials.

(e) It is noteworthy that replacing a five-year payback criterion with a more stringent three-year requirement reduces the expected opportunities for cogeneration by 330 MW.

A summary of the various types of estimated market potential is shown in Exhibit 8. An immediate policy question is how to reduce the gap between the implementation potential of about 1300 MW and those larger potentials based on economic and financial feasibility criteria.

A comparison of these results with earlier estimates of market potential is contained in Exhibit 9. Note that the most recent Acres estimates point to a far larger market than those presented in earlier studies. But a more valid comparison would focus on industrial markets alone as the earlier reports analyzed only the industrial sector. This single sector comparison shows that the latest estimates of market potential are within the earlier range in the case of financial and implementation potentials and above the previous estimates in the case of economic potentials.

5 - CONCLUSIONS

Market opportunities for cogeneration are clearly substantial. Depending on the choice of investment criteria, 1300 MW to 1700 MW of cogeneration capacity are financially feasible in the industrial and buildings sectors. Based on a provincial perspective and life-cycle cost analysis, an even greater potential of 3800 MW could be developed cost-effectively.

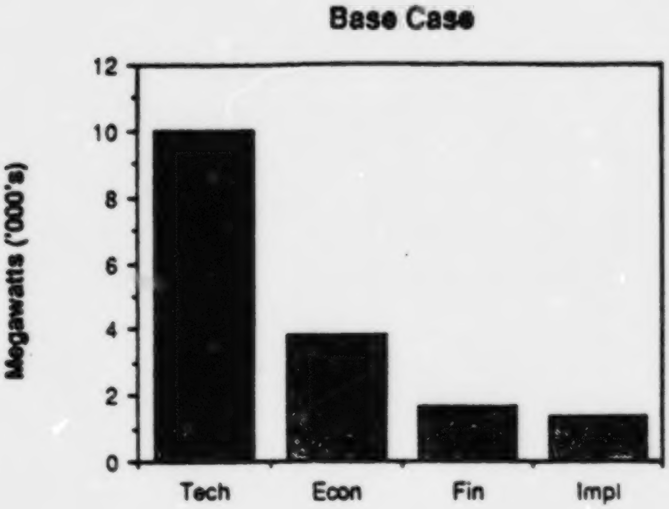

EXHIBIT 8
COGENERATION POTENTIAL IN ONTARIO

BASE CASE

EXHIBIT 9

COMPARISON OF ESTIMATES OF COGENERATION MARKET POTENTIAL

		Additional Potential for Cogeneration by Type of Potential (MW)			
	Target Year	Technical	Economic	Financial	Implementation
Leighton and Kidd (1977)	1985	3 500 (I)	-	-	1 500 (I)
Ontario Hydro (1978)	2000	2 800 (I)	-	-	-
Acres Shawinigan Ltd (1979)	2000	1 000 (I*)	650 (I*)	375 (I*)	-
Royal Commission (1980)	2000	2 300 (I)	-	400 (I)	-
Cogeneration Associates (1980)	1990	4 600 (I)	-	1 800 (I)	-
Ontario Hydro (1981)	2000	3 300 (I)	-	-	450 (I)
Acres (1982)	2000	575 (I*)	140 (I*)	-	
Diener and Dupont (1984)	2000	1 125 (I*)	385 (I*)	-	
Ministry of Energy (1985)	2000	5 000 (I)	500 to 1 125	-	-
Ontario Hydro (1985, 1986)	2000	- -	150 to 1 000 (I)	150 to 1 000 (I)	
Select Committee (1986)	2000	- -	-	300 to 1 400 (I)	
Range of Estimates		1 000 to 5 000	500 to 1 125	150 to 1 800	150 to 1 500

I - Industrial
I* - Large Industrial

Acres (1987)

- Total Potential	10,000	3,800	1,700	1,300
- Industrial Potential	3,800	1,900	1,700	1,300

The daunting question is therefore not whether there are market opportunities, but rather how these opportunities could be realized over the coming years.

Through the rest of today, seminars speakers will be providing practical advice on how to translate market potential into viable investment projects. At the risk of impinging on their turf let me suggest briefly and in a general way, four of the ingredients I feel are necessary to realize the full potential of cogeneration.

1. Government Leadership

   Most important, and this seminar is an example, the government should send signals to all interested parties (industrial and institutional energy users, suppliers of equipment and services and electric utilities) that it is serious about cogeneration. Government policies and programs should address the information gaps, the uncertainty and the perceived risks associated with cogeneration investments. Initiatives should include information and publicity programs and demonstration projects, all tailored to specific subsectors where the gaps between economic and implementation potentials are the greatest.

2. Ontario Hydro Commitment

   Surveys by the Canadian Energy Research Institute and others have shown that industry perceives Ontario Hydro to be less than enthusiastic about cogeneration. To the extent that Ontario Hydro has taken organizational and financial steps to encourage cogeneration the perception is not entirely accurate. Nonetheless much remains to be done, in particular the implementation of a more integrated supply/demand-based investment planning process and active promotion of economically desirable cogeneration projects.

3. Industrial and Institutional Commitment

With the help of government and Ontario Hydro initiatives, industrial and institutional energy users should promote cost-effective cogeneration within their own organizations. If one is already dismayed by the evidence that three-year paybacks are required of energy productivity investments, one would be shocked to see projects with three-year paybacks (33% return on investment) fall short of implementation. In this regard, demonstration projects may be the most effective means of creating industrywide awareness and commitment.

4. Innovative Marketing

Suppliers of cogeneration equipment and services have the necessary technical knowhow to plan, design and implement cogeneration projects. The missing ingredient is frequently the marketing of these goods and services in a way that meets client needs. In many cases these needs pertain to innovative financing plans that do not require energy users to dip into their limited capital budgets. For example, 'savings financing' could be used to fund projects, with the suppliers compensated out of energy savings accruing to the customer organization.

But enough of general observations. Let me yield the podium to those better versed in technical and implementation issues.

Thank you for your attention.

Packaged Systems

By
B. G. Ander, P.Eng.
Atlas Polar Company Limited

3

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INCORPORATED 1938

Experience and Prospects in Ontario
A One Day Seminar on Cogeneration
March 10, 1988

PACKAGED SYSTEMS

Presented by: B.E. Ander, P. Eng.
Vice President · Power Division
Atlas Polar Company Limited

Experience and Prospects in Ontario
A One Day Seminar on Cogeneration
March 10, 1988

PACKAGED SYSTEMS

Presented by: R.B. Ander, P. Eng.
Vice President - Power Division
Atlas Polar Company Limited

INTRODUCTION

(Slide 1) It is a pleasure to speak today at this Seminar sponsored by the Ministry of Energy. For those of us who have watched this market develop, I believe we will see a changing emphasis at this and future cogeneration seminars. In past years, a curiosity factor has resulted in excellent attendance at events involving cogeneration presentations. Many in attendance were looking for basic information and an update on the industry.

(Slide 1a) Now there are reasons to believe that this will change. There are clear policies from the Ministry of Energy and Ontario Hydro that Cogeneration satisfies two important energy goals in Ontario: Diversify our sources of energy supply and conservation via improved generating efficiency. I look forward to observing active discussions among representatives from MOE, Ontario Hydro, the Gas Utilities, Packagers and indudustry as we look for innovative solutions to bring down the barriers to Cogeneration in Ontario.

EXPERIENCE

(Slide 2) Atlas Polar has been asked to present a talk on Packaged Systems due to our active involvement in this market representing Waukesha Engines, a leading manufacturer of natural gas reciprocating engines for prime power, stationary applications. Atlas Polar has been a distributor for Waukesha Engines since 1940, and has manufactured generator sets with heat recovery equipment on a variety of fuels: natural gas, digester gas, biogas and diesel.

(Slide 3) We are proud to announce that 1988 represents a special year for Atlas Polar; our 50th Anniversary. As you would expect, none of the original employees are still with the company. None the less, we bring our combined experience to the Cogeneration market.

(Slide 3a) Atlas Polar's specific Cogeneration experience includes the following projects dating back to 1959:

1959 Sarnia Sewage Treatment Plant
(3) Waukesha V85 @ 900 RPM
Digester Gas with Exhaust Heat Recovery
Engineer: MacLaren Engineers (Toronto)

Experience and Prospects in Ontario
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Page 2

1983 Folkema Farms (Ingersoll, Ontario)
(1) Waukesha VRG155, 13 KW @ 1800 RPM
Digester Gas with Exhaust Heat Recovery
Engineer: MacLaren Engineers (Toronto)

1984 Linden Lee Farms (P.E.I., Canada)
(1) Waukesha VRG330, 40 KW @ 1800 RPM
Digester Gas with Exhaust Heat Recovery
Engineer: Canviro Consultants (Kitchener)

1984 University of Ottawa (Enerdemo Project)
(1) Waukesha L5790, 600 KW @ 1200 RPM
Natural Gas with Jacket Water and Exhaust Heat Recovery
Engineer: Cogeneration Associates (Toronto)

(Slide 3b) 1985 Peterborough Sewage Treatment Plant
(1) Waukesha H2476G, 200 KW @ 1200 RPM
Digester Gas with Jacket Water and Exhaust Heat Recovery
Engineer: MacLaren Engineers (Toronto)

1986 Northeast Energy Services
(2) Waukesha L5108G, 425 KW each @ 1200 RPM
Biogas from potato processing plant with Jacket Water and Exhaust Heat Recovery
Engineer: ADI Limited (Fredericton)

1987 Union Gas Limited (Demo Project)
(1) Waukesha VRG330S, 64 KW @ 1800 RPM
Natural Gas with Jacket Water and Exhaust Heat Recovery
Engineer: Parker Consultants (Burlington)

1988 Northwest Utilities (Edmonton)
(1) Waukesha F1197G, 115 KW @ 1200 RPM
Natural Gas
Engineer: Cogeneration Associates (Toronto)

The U.S. and European Cogeneration market has developed into thriving industries. As a result, Waukesha Engine has considerable experience in total which we draw upon. In the past 10 years alone, Waukesha distributors have installed more than 500 large bore, gas engines in the U.S. and Canada on heat recovery installations.

PACKAGED SYSTEMS

(Slide 4) When we were asked by the Ministry to present on this topic, it raised several questions regarding the definition of Packaged Systems.

(Slide 5) Many concepts come to mind. Pre-engineered, complete, turn-key, low cost, easy to install. Does the industry offer such systems today that would benefit the Ontario Cogeneration market? I will return to this question.

(Slide 6) What does a "Package" include? A prime mover such as a reciprocating engine or turbine, which converts fuel to mechanical power and heat; (Slide 7) A heat recovery system which may include an exhaust heat recovery silencer; (Slide 8) a generator or alternator; and a (Slide 9) control system. Other components include a heat rejection system for use when the heat available from the prime mover exceeds the site requirements and an electrical interconnection between the generator set and the facility loads and utility.

(Slide 10) Determining the prime mover is the most critical aspect of equipment selection. In general terms, reciprocating gas engines are most efficient below several megawatts. Gas and steam turbines are more appropriate choices in the larger systems. Just as important as the KW rating is the thermal requirement. Reciprocating engines produce hot water and low pressure steam most economically. High pressure steam applications tend to favour turbines.

The prime mover will dictate the maintenance and operating costs for the cogeneration system. The other components are relatively maintenance free. Many independant U.S. Packagers do not place much emphasis on the prime mover or it's life cycle costs. I recommend that the owner must know these costs in detail and firm up a fixed maintenance contract with the engine manufacturer's distributor. If a packager is not willing to stand behind estimated hours to minor or major overhauls, be very cautious.

(Slide 5) Does Waukesha Engine manufacture a Pre-Packaged Cogeneration System? (Slide 11) In response to the growing demand for pre-engineered packages at specific KW sizes, Waukesha introduced a line of gas cogeneration modules ranging from 30 to 375KW. (Slide 12) These are summarized in the Waukesha package distributed this morning. Are these packages appropriate for the Ontario market? The answer is yes, in some instances.

As we know, the economics for Cogeneration in Ontario is very tight. The application must be well-engineered but not over-engineered. The prime mover must be properly sized and efficient. One of these pre-engineered packages may or may not fit the exact requirements of your application.

When there is a good fit for a module, we have the benefit of pre engineered schematics (Slide B) and actual manufacturing drawings which help the engineer come up to speed very quickly. Pricing is also readily available as we can avoid the time consuming detailed costing.

However, more times than not, the application requires us to pick the most appropriate engine and consider a series of factors depending on specific site requirements and build a custom set (Slide 14):

Speed - 900, 1200 or 1800 RPM
Naturally aspirated or turbo-intercooled
Rich burn or lean burn
Jacket Water heat recovery and/or exhaust heat recovery
Hot water or steam production or both

The vast majority of Waukesha installations are custom engineered. All of Atlas Polar's cogeneration installations have been custom. Pre-designed systems are not the answer for the broad market in Ontario. Experience is the key to bring down project costs. Your luncheon speaker is Mr. Keith Davidson, Director of Cogeneration Research at Chicago's Gas Research Institute. In a February 1988 Ashrae Journal article he states, (Slide 14a):

> "Equipment costs are only part of the first cost picture. Installation cost, too, has had a significant and somewhat unexpected high impact on cogeneration capital investments and their attractiveness. Estimates for mature installation costs for a nominal 40 KW package fall in the $150 - $300 US/KW range and include piping runs for natural gas fuel, hot water supply/return, chilled water supply/return (for systems with heat driven cooling), and condenser water supply/return (for systems with aftercooled engines and/or heat driven cooling), and electrical runs to the main bus. However, documented costs based on recent experience generally have been well in excess of this cost range. Much of this can be attributed to the unfamiliarity of mechanical contractors with cogeneration equipment and their tendency to pad in a "fear factor" for fixed bid projects, but also to approaching installation as a major engineering project with costs for consulting engineers, installation designers and project managers.

> As cogeneration technology and markets continue to mature and packagers and installers become more familiar with cogeneration as "just another piece of packaged equipment", installation costs should gravitate down."

Anytime packagers and/or installers lack experience, costs will be padded or mistakes will be made. We need packagers, contractors and consultants with experience. The packagers must be able to design and supply all components of the system. The after sale training, service and parts must be in place.

Everytime a new system gets installed, someone gains invaluable knowledge that benefits the next installation. Eventually, the energy picture in Ontario will match the U.S. conditions. At that time you want the installed equipment costs to be less than current levels, and that comes with installation experience.

Cogeneration Economics

(Slide 15) Included in the Waukesha handout is the Waukesha Cogeneration Handbook. Section 7 reviews the basic parameters in calculating the economics of an installation. Table One illustrates the Waukesha Cogen Program that is widely used by distributors to simplify equipment selection and calculate the cogeneration system annual energy savings.

Also included in the handout (on the left hand pocket) is a sample calculation based on a hospital located in Northern Ontario which came to me as an inquiry last year.

(Slide 16) The Base Case reported the following site conditions:

1.	Heating Load	4,000,000	BTU/hr
2.	Base Electrical Load	500	KW
3.	Peak Demand	1200	KW
4.	Day/yr of operation	330	
5.	Hrs/day of operation	24	
6.	Demand charge	$5.00	/KW
7.	Electrical rate	$.040	/KW-hr
8.	Excess Power Sale Rate	$.000	/KW-hr
9.	Boiler Fuel Cost - Nat. gas	$.40	/100 cu. ft.
10.	Engine Fuel Cost - Nat. gas	$.40	/100 cu. ft.
11.	Engine Fuel Cost - Diesel	$.00	/gal
12.	Altitude	200	ft.
13.	Ambient Temperature	100	degrees F.

(Slide 17) Other assumptions include boiler efficiency, gas low heat valve, maintenance estimate, and fuel, electrical and maintenance inflation rates.

(Slide 18) The maintenance cost is developed using the Waukesha Life Cycle Cost Analysis Program. For a specific engine, HP and RPM, the program calculates a cost for preventative maintenance parts, overhaul parts, oil consumption and labour. Simply, if you bank 1.5 cents every KW hr in operation, you will have sufficient funds available when maintenance is required.

(Slide 19) The Cogen program asks us to select an engine family based on our knowledge of the Waukesha product line. In this case we specified one (1) unit @ 1200 RPM from the VHP GSI family, a large bore turbocharged, intercooled engine. The program selected a VHP3600GSI rated 500 KW, equal to the base load electrical demand. The total heat recoverable is about 3 million BTU/hr, again less than the base heating load in the hospital. As a result, the system is base loaded electrically and thermally and does not waste any heat.

(Slide 20) The energy costs before cogeneration equal $454,800.00 annually. The installed equipment cost for a 500 KW system is $556,000.00 or about $1,100.00/KW. This is our estimate which includes engineering, all hardware and controls, heat recovery equipment and installation by contractors. Considering fuel consumption, maintenance and reduced electrical costs, the annual energy savings are $57,002.00. A simple payback is just under 10 years.

(Slide 21) Revisions one to the base case incorporates three likely cost saving measures:

1. An improved fuel cost via a long term contract with the gas utility.
   $.38/100 cu. ft. (5% reduction)

2. An improved maintenance cost via a long term contract with the packager.
   $.012/KW-hr (20% reduction)

3. Lower installed equipment cost.
   $528,000.00 (5% reduction)

(Slide 22) The net results of these combined measures increase the annual net savings to $72,482.00 and reduce the simple payback to 7.28 years.

(Slide 23) The second revision assumes that all revision one reductions are in place and outside funding further reduces the net installed cost. For illustration purposes we have shown a grant equal to 28.9% of the capital investment, totalling $153,000.00. This reduces the installed cost to $375,000.00.

(Slide 24) The system savings are still $72,482.00 annually but the payback has fallen to 5 years, an acceptable result.

SUMMARY

(Slide 25) I would like to conclude by stressing two points from the presentation:

1. Packagers, contractors and consultants must gain experience in designing, manufacturing and installing custom cogeneration packages. With experience, the market can look forward to lower costs and reliable installations.
2. Funding in the way of "seed" money will allow installations to move forward so all parties can learn together including Ontario Hydro, MOE and the gas Utilities.

(Slide 26) Waukesha Engine and Atlas Polar wish to express our appreciation to the Ministry of Energy for allowing us to express some views on this very important topic.

REFERENCES:

1. Keith G. Davidson. Packaged Cogeneration. Ashrae Journal. February 1988.
2. Waukesha Cogeneration Handbook. Copyright 1986.
3. Honourable Robert C. Wong. Ontario Hydro Parallel Generation Workshop 87. October 13, 1987.
4. Robert Sheppard. Ontario Hydro tries no-growth Options. Globe and Mail. Report on Business. February 1, 1988.

ATTACHMENTS

1. BASE CASE, 500 KW Cogen Analysis Printout
2. Revision One to Base Case.
3. Revision Two to Base Case.

Estimated Cogeneration Calculations
Distributor: ATLAS POLAR
Phone:
Proj. name: BASE CASE
Today's date: 10-Mar-88

Computer
Operator:
Salesman:

Inputs:

SITE CONDITIONS

1. Heating load	4,000,000	BTU/hr
2. Base electrical load	500	kW
3. Peak demand	1200	kW
4. Days/yr of operation	330	
5. Hrs/day of usage	24	
6. Demand charge	$5.00	/kW
7. Electrical rate	$0.040	/kW-Hr
8. Excess power sale rate	$0.000	/kW-Hr
9. Boiler fuel cost - Nat. gas	$0.40	/100 cu. ft.
10. Engine fuel cost - Nat. gas	$0.40	/100 cu. ft.
11. Engine fuel cost - Diesel	$0.00	/gal
12. Altitude	200	feet
13. Ambient Temperature	100	degrees, F.

ASSUMPTIONS

1. Min. exhaust temp	350	degrees F.
2. Specific heat, Cp	0.255	
3. % hours @ Pk load	25%	
4. Boiler efficiency	0.750	
5. Inst./acc. costs	300%	
6. Gas LHV BTU/cu ft	900	
7. Fuel oil dens.	7.2	lb/gal
8. Fuel oil energy	18400	BTU/lb
9. Maintenance est.	$0.0150	/kW-Hr
10. Fuel infl. rate	4%	
11. Elect. infl. rate	5%	
12. Mtce. infl. rate	4%	
13. Finance rate	11%	
14. List price disc.	10%	

ENGINE PARAMETERS

1. Engine RPM	1200	RPM
2. Number of units	1	
3. Baseload type (1=Elect., 2=Thermal)	1	
4. Engine family	2	

0=Clinton, Int. (65 - 370 kW)
1=VHP G (235 - 975 kW)
2=VHP GSI (335 - 1475 kW)
3=VHP D (215 - 640 kW)
4=VHP DS (300 - 920 kW)
5=VHP DSI (375 - 1530 kW)
6=VRG (24 - 64 kW)
7=Pre-packaged modules w/induction gen. (29 - 370 kW)
8=VS DS and DSI (145 - 275 kW)
9=VRD (24 - 65 kW)
10=GL (335 - 1100 kW)

* * *

Outputs:

MODEL SELECTION

1. Model	VHP3600GSI	
2. Rated KW @ std. conditions	550	kW
3. KW Supplied	500	kW
4. BMEP	134	psi
5. Fuel consumption	5,649,000	BTU/hr
6. Heat rej. - jacket water	1,700,000	BTU/hr
7. Heat rej. - Exhaust @ 85 F.	1,350,000	BTU/hr
8. Heat rej. - Lube oil	234,000	BTU/hr
9. Heat rej. - Intercooler	153,000	BTU/hr
10. Exhaust temp	1120	degrees F.
11. Exhaust air flow	3524	CFM
12. Base ENGINATOR price	$138,929	

Estimated Cogeneration Calculations
Distributor: ATLAS POLAR
Phone:
Proj. name: BASE CASE
Today's date: 10-Mar-88

Computer
Operator:
Salesman:

SYSTEM CALCULATIONS

1. Exhaust heat recovery	916,000 BTU/hr
2. Total heat recoverable	3,003,000 BTU/hr
3. Recoverable energy eff.	53.2%
4. Shaft efficiency	30.2%
5. Total system efficiency	83.4%
6. Qualified Facility eff.	56.8% (42.5% Minimum)
7. Est. radiation (incl. gen.)	506,000 BTU/hr
8. Excess system heat (wasted)	0 BTU/hr

	1988	1989	1990	1991	1992
	============	============	==========	==========	=========
CURRENT ANNUAL ENERGY COSTS					
1. Electrical energy cost	$213,840	$224,532	$235,759	$247,547	$259,924
2. Electrical demand cost	$72,000	$75,600	$79,380	$83,349	$87,516
3. Boiler energy cost	$168,960	$175,718	$182,747	$190,057	$197,659
4. Total energy cost	$454,800	$475,850	$497,886	$520,953	$545,100
COGENERATION SYSTEM COSTS					
1. Installed equipment cost	$556,000				
2. Engine fuel costs	$198,845	$206,799	$215,071	$223,673	$232,620
3. Estimated maintenance costs	$59,400	$61,776	$64,247	$66,817	$69,490
4. Elect. power cost (sales)	$55,440	$58,212	$61,123	$64,179	$67,388
5. Elect. demand cost	$42,000	$44,100	$46,305	$48,620	$51,051
6. Boiler energy reqd., BTU/yr	7.90E+09	7.90E+09	7.90E+09	7.90E+09	7.90E+09
7. Boiler energy cost	$42,113	$43,798	$45,556	$47,372	$49,267
8. Total cogen system costs	$397,798	$414,684	$432,295	$450,661	$469,815
9. System savings	$57,002	$61,166	$65,591	$70,292	$75,284
10. Cumulative net savings	($560,158)	($560,609)	($556,686)	($547,630)	($532,585)

INVESTMENT ANALYSIS

1. Simple payback	9.75 Years
2. Internal rate of return (Five years)	-14.7%
3. Present value of system savings (Line 9) at assumed finance rate	$239,937

The above results represent, for preliminary information purposes only, calculations involving certain estimated and assumed variables with respect to a generally proposed project. Prior to any purchase of a cogeneration system, a prospective customer, or his authorized representative, should compute or confirm the above results in light of the entire project, as THE ABOVE RESULTS ARE NOT WARRANTED, EXPRESSLY OR IMPLICITLY, AS TO COMPLETENESS, ACCURACY, OR FITNESS.

```
                    Estimated Cogeneration Calculations
                    Distributor: ATLAS POLAR            Computer
                    Phone:                              Operator:
                    Proj. name:  REV. 1                 Salesman:
                    Today's date:    10-Mar-88

Inputs:

SITE CONDITIONS                                     ASSUMPTIONS
  1. Heating load                 4,000,000 BTU/hr    1. Min. exhaust temp      350 degrees F.
  2. Base electrical load               500 kW        2. Specific heat, Cp    0.255
  3. Peak demand                       1200 kW        3. % hours @ Pk load      25%
  4. Days/yr of operation               330           4. Boiler efficiency    0.750
  5. Hrs/day of usage                    24           5. Inst./acc. costs      280%
  6. Demand charge                    $5.00 /kW       6. Gas LHV BTU/cu ft      900
  7. Electrical rate                 $0.040 /kW-Hr    7. Fuel oil dens.         7.2 Lb/gal
  8. Excess power sale rate          $0.000 /kW-Hr    8. Fuel oil energy      18400 BTU/Lb
  9. Boiler fuel cost - Nat. gas      $0.38 /100 cu. ft.  9. Maintenance est.  $0.0120 /kW-Hr
 10. Engine fuel cost - Nat. gas      $0.38 /100 cu. ft. 10. Fuel infl. rate       4%
 11. Engine fuel cost - Diesel        $0.00 /gal     11. Elect. infl. rate       5%
 12. Altitude                           200 feet     12. Mtce. infl. rate        4%
 13. Ambient Temperature                100 degrees, F.  13. Finance rate        11%
                                                     14. List price disc.       10%
ENGINE PARAMETERS
  1. Engine RPM                        1200 RPM
  2. Number of units                      1
  3. Baseload type                        1
     (1=Elect., 2=Thermal)
  4. Engine family                        2
     0=Clinton, Int. (65 - 370 kW)
     1=VHP G (235 - 975 kW)
     2=VHP GSI (335 - 1475 kW)
     3=VHP D (215 - 640 kW)
     4=VHP DS (300 - 920 kW)
     5=VHP DSI (375 - 1530 kW)
     6=VRG (24 - 64 kW)
     7=Pre-packaged modules w/induction gen. (29 - 370 kW)
     8=VS DS and DSI (145 - 275 kW)
     9=VRD (24 - 65 kW)
    10=GL (335 - 1100 kW)

******************************************************************************************

Outputs:

MODEL SELECTION
  1. Model                          VHP3600GSI
  2. Rated KW @ std. conditions            550 kW
  3. KW Supplied                           500 kW
  4. BMEP                                  134 psi
  5. Fuel consumption                5,649,000 BTU/hr
  6. Heat rej. - jacket water        1,700,000 BTU/hr
  7. Heat rej. - Exhaust @ 65 F.     1,350,000 BTU/hr
  8. Heat rej. - Lube oil              234,000 BTU/hr
  9. Heat rej. - Intercooler           153,000 BTU/hr
 10. Exhaust temp                         1120 degrees F.
 11. Exhaust air flow                     3524 CFM
 12. Base ENGINATOR price             $138,929
```

Estimated Cogeneration Calculations
Distributor: ATLAS POLAR **Computer**
Phone: **Operator:**
Proj. name: REV. 1 **Salesman:**
Today's date: 10-Mar-88

SYSTEM CALCULATIONS

1. Exhaust heat recovery	916,000 BTU/hr
2. Total heat recoverable	3,003,000 BTU/hr
3. Recoverable energy eff.	53.2%
4. Shaft efficiency	30.2%
5. Total system efficiency	83.4%
6. Qualified Facility eff.	56.8% (42.5% Minimum)
7. Est. radiation (incl. gen.)	506,000 BTU/hr
8. Excess system heat (wasted)	0 BTU/hr

	1988	1989	1990	1991	1992
CURRENT ANNUAL ENERGY COSTS					
1. Electrical energy cost	$213,840	$224,532	$235,759	$247,547	$259,924
2. Electrical demand cost	$72,000	$75,600	$79,380	$83,349	$87,516
3. Boiler energy cost	$160,512	$166,932	$173,610	$180,554	$187,776
4. Total energy cost	$446,352	$467,064	$488,748	$511,450	$535,217
COGENERATION SYSTEM COSTS					
1. Installed equipment cost	$528,000				
2. Engine fuel costs	$188,903	$196,459	$204,317	$212,490	$220,989
3. Estimated maintenance costs	$47,520	$49,421	$51,398	$53,454	$55,592
4. Elect. power cost (sales)	$55,440	$58,212	$61,123	$64,179	$67,388
5. Elect. demand cost	$42,000	$44,100	$46,305	$48,620	$51,051
6. Boiler energy reqd., BTU/yr	7.90E+09	7.90E+09	7.90E+09	7.90E+09	7.90E+09
7. Boiler energy cost	$40,008	$41,608	$43,272	$45,003	$46,803
8. Total cogen system costs	$373,870	$389,799	$406,414	$423,745	$441,823
9. System savings	$72,482	$77,265	$82,334	$87,704	$93,394
10. Cumulative net savings	($513,598)	($492,829)	($464,706)	($428,119)	($381,819)

INVESTMENT ANALYSIS

1. Simple payback	7.28 Years
2. Internal rate of return (Five years)	-7.4%
3. Present value of system savings (Line 9) at assumed finance rate	$301,409

The above results represent, for preliminary information purposes only, calculations involving certain estimated and assumed variables with respect to a generally proposed project. Prior to any purchase of a cogeneration system, a prospective customer, or his authorized representative, should compute or confirm the above results in light of the entire project, as THE ABOVE RESULTS ARE NOT WARRANTED, EXPRESSLY OR IMPLICITLY, AS TO COMPLETENESS, ACCURACY, OR FITNESS.

```
                    Estimated Cogeneration Calculations
                    Distributor: ATLAS PLAR             Computer
                    Phone:                              Operator:
                    Proj. name:  REV. 2                 Salesman:
                    Today's date:   10-Mar-88

Inputs:

SITE CONDITIONS                                       ASSUMPTIONS
  1. Heating load                4,000,000 BTU/hr      1. Min. exhaust temp        350 degrees F.
  2. Base electrical load              500 kW         2. Specific heat, Cp      0.255
  3. Peak demand                      1200 kW         3. % hours @ Pk Load        25%
  4. Days/yr of operation              330            4. Boiler efficiency      0.750
  5. Hrs/day of usage                   24            5. Inst./acc. costs        170%
  6. Demand charge                  $5.00 /kW         6. Gas LHV BTU/cu ft        900
  7. Electrical rate               $0.040 /kW-Hr      7. Fuel oil dens.          7.2 lb/gal
  8. Excess power sale rate        $0.000 /kW-Hr      8. Fuel oil energy       18400 BTU/lb
  9. Boiler fuel cost - Nat. gas    $0.38 /100 cu. ft. 9. Maintenance est.   $0.0120 /kW-Hr
 10. Engine fuel cost - Nat. gas    $0.38 /100 cu. ft. 10. Fuel infl. rate          4%
 11. Engine fuel cost - Diesel      $0.00 /gal        11. Elect. infl. rate         5%
 12. Altitude                         200 feet        12. Mtce. infl. rate          4%
 13. Ambient Temperature              100 degrees, F. 13. Finance rate             11%
                                                      14. List price disc.         10%
ENGINE PARAMETERS
  1. Engine RPM                       1200 RPM
  2. Number of units                     1
  3. Baseload type                       1
     (1=Elect., 2=Thermal)
  4. Engine family                       2
     0=Clinton, Int. (65 - 370 kW)
     1=VHP G (235 - 975 kW)
     2=VHP GSI (335 - 1475 kW)
     3=VHP D (215 - 640 kW)
     4=VHP DS (300 - 920 kW)
     5=VHP DSI (375 - 1530 kW)
     6=VRG (24 - 64 kW)
     7=Pre-pacaaged modules w/induction gen. (29 - 370 kW)
     8=VS DS and DSI (145 - 275 kW)
     9=VRD (24 - 65 kW)
    10=GL (335 - 1100 kW)

**************************************************************************************

Outputs:

MODEL SELECTION
  1. Model                        VHP3600GSI
  2. Rated KW @ std. conditions          550 kW
  3. KW Supplied                         500 kW
  4. BMEP                                134 psi
  5. Fuel consumption              5,649,000 BTU/hr
  6. Heat rej. - jacket water      1,700,000 BTU/hr
  7. Heat rej. - Exhaust @ 85 F.   1,350,000 BTU/hr
  8. Heat rej. - Lube oil            234,000 BTU/hr
  9. Heat rej. - Intercooler         153,000 BTU/hr
 10. Exhaust temp                       1120 degrees F.
 11. Exhaust air flow                   3524 CFM
 12. Base ENGINATOR price           $138,929
```

Estimated Cogeneration Calculations
Distributor: ATLAS PLAR
Phone:
Proj. name: REV. 2
Today's date: 10-Mar-88

Computer
Operator:
Salesman:

SYSTEM CALCULATIONS

1. Exhaust heat recovery	916,000 BTU/hr
2. Total heat recoverable	3,003,000 BTU/hr
3. Recoverable energy eff.	53.2%
4. Shaft efficiency	30.2%
5. Total system efficiency	83.4%
6. Qualified Facility eff.	56.8% (42.5% Minimum)
7. Est. radiation (incl. gen.)	506,000 BTU/hr
8. Excess system heat (wasted)	0 BTU/hr

	1988	1989	1990	1991	1992
CURRENT ANNUAL ENERGY COSTS					
1. Electrical energy cost	$213,840	$224,532	$235,739	$247,547	$259,924
2. Electrical demand cost	$72,000	$75,600	$79,380	$83,349	$87,516
3. Boiler energy cost	$160,512	$166,932	$173,610	$180,554	$187,776
4. Total energy cost	$446,352	$467,064	$488,748	$511,450	$535,217
COGENERATION SYSTEM COSTS					
1. Installed equipment cost	$375,000				
2. Engine fuel costs	$188,903	$196,459	$204,317	$212,490	$220,989
3. Estimated maintenance costs	$47,520	$49,421	$51,398	$53,454	$55,592
4. Elect. power cost (sales)	$55,440	$58,212	$61,123	$64,179	$67,388
5. Elect. demand cost	$42,000	$44,100	$46,305	$48,620	$51,051
6. Boiler energy reqd., BTU/yr	7.90E+09	7.90E+09	7.90E+09	7.90E+09	7.90E+09
7. Boiler energy cost	$40,008	$41,608	$43,272	$45,003	$46,803
8. Total cogen system costs	$373,870	$389,799	$406,414	$423,745	$441,823
9. System savings	$72,482	$77,265	$82,334	$87,704	$93,394
10. Cumulative net savings	($343,768)	($304,318)	($255,459)	($195,855)	($124,005)

INVESTMENT ANALYSIS

1. Simple payback	5.17 Years
2. Internal rate of return (Five years)	3.2%
3. Present value of system savings (Line 9) at assumed finance rate	$301,409

The above results represent, for preliminary information purposes only, calculations involving certain estimated and assumed variables with respect to a generally proposed project. Prior to any purchase of a cogeneration system, a prospective customer, or his authorized representative, should compute or confirm the above results in light of the entire project, as THE ABOVE RESULTS ARE NOT WARRANTED, EXPRESSLY OR IMPLICITLY, AS TO COMPLETENESS, ACCURACY, OR FITNESS.

Technology Overview
Large Gas and Steam Turbines

By
S. van der Linden
Asea Brown Boveri Energy Services, Inc. - USA

4

MARCH 10/88 SEMINAR ON COGENERATION COGENERATION

COGENERATION — **ALTERNATIVE ENERGY**

TECHNOLOGY OVERVIEW — **LARGE GAS AND STEAM TURBINES**

S. van der Linden - Assistant Vice President
Asea Brown Boveri Energy Services, Inc - USA

I would like to express my thanks to the Ontario Minister of Energy, to be given this opportunity to provide a Technology Overview of larger Cogeneration systems.

It is indeed a pleasure to be back in Toronto, it seems like a home coming event, having first arrived in Toronto in 1957, left in 1959 and resided in different parts of the globe, and now settled in New Jersey USA. Not too far away. During a sojourn in the mid 60's in Australia, at about the time when Australian natural gas as an energy source loomed on the horizon, the debate was about whether a policy of dispersed power plants should be set, distribute the gas to specific industry or urban load centers with smaller power plants to serve specific needs. Well, it appears to me that today cogeneration is specifically filling that requirement in North America.

From a US perspective the cogeneration market is vibrant, more settled though and not as wild and volatile when at first everyone jumped on the cogeneration wagon. In the US 1987 filings for cogen totaled 13,000 MW's over 373 facilities versus 1986 17,943 MW's in 555 facilities. The planned 1987 capacity would have 10,000 MW coal/or gas fired of which 90% of the facilities would be larger than 40 MW's and most applications are for California and NY with site ratings 40/80 MW's.

In the US the Fuel Use Act has been repealed - opportunities exist for independent power producers (IPP's), who can locate power plants exactly where they are wanted ie. dispersed versus centralized.

The Utilities in the US now are taking a new role in the capacity market and are diversifying into the non-regulated market such as cogeneration and IPP through affiliated energy companies, 34 such companies all together.

Since 1984, my company have been involved in 9 US cogeneration projects totaling over 2,000 MW primarily for the industrial and process markets such as Chemical, Petro-Refineries, Pulp and Paper, and Enhanced Oil Recovery (EOR).

GT HISTORY

Since the first patent of a gas turbine was granted in 1791 in England to John Barbor, inventors have continuously tackled the Brayton Cycle and the number of patents have steadily increased.

The economic use of the simple cycle gas turbine for the generation of electricity in a public power station was first realized in 1939, the design of this machine is illustrated in Fig. 1. This set was ordered by the Municipal Power Station in Neuchâtel, Switzerland. Fig. 1A

The introduction of the gas turbine in the field of power generation is the realization of a long cherished dream of engineers. Two thoughts can be suggested. First, the simplification of equipment and the desire to eliminate the steam plant consisting of steam boilers, steam engine, and condensing plant. Second, to drive directly from the rotary movement of the turbine, the generator for producing electricity, and to do away with the crank and connecting rod mechanism of the steam engine.

The first step in this direction of simplification was of course the advent of the steam turbine, that did away with the reciprocating steam engine, with the gas turbine as a further step. Indeed, the steam turbine simplified welded rotor design introduced in 1926 was adapted to the gas turbine to eliminate separate discs or wheels, and remains a feature for both steam and gas turbines of BBC design.

Earlier development work in 1910 on the Holzwarth principal Fig. 2 was abandoned with the advent of the axial compressor development, which made continuous combustion at constant pressure possible.

GT THERMO-DYNAMICS

The GT principle is illustrated in Fig. 3, the compressor delivers air to the single large combustor where fuel is added. The resultant hot gasses expand through the turbine providing sufficient power to drive the compressor (+/- 66% load) and the balance to drive the generator. The generator is driven from the compressor (or cold) end. In Fig. 4 the temperature/entropy diagram illustrates the Brayton Cycle. Gas turbine efficiencies are constantly improving with advancing technology, and Fig. 5 illustrates the trend of increasing turbine inlet temp. versus efficiency improvements.

In the combined cycle - gas/steam turbine process the exhaust energy is recovered in a heat recovery steam generator to produce steam for the bottoming cycle, the steam or Rankine cycle. Fig. 6 is a typical temp/entropy diagram, with the principle illustrated in Fig. 7.

COMBINED CYCLE / COGEN THERMO DYNAMICS

As in the conventional combined cycle the cogeneration cycle Fig. 8 the steam cycle can now be expanded to provide heat to process either as a back pressure turbine or extraction/condensing unit. There maybe process requirements that would eliminate the ST and simply direct the steam directly to process or direct the exhaust heat directly to process. Cycle diagrams Fig. 9 & 10 illustrates two different process steam requirements.

Variables affecting the cycle performance in Fig. 9 and 10 would be as follows. Heat recovery in a single pressure steam generator. The pinch point P and approach temp A set what can be recovered. See Fig. 11. In Fig 12, 13, & 14 other variables of condenser pressure ambient air temp. and pressure are illustrated.

To optimize for maximum fuel utilization dual or triple pressure HRSG can be employed, Fig 15 illustrates a dual pressure system with a cycle as represented in Fig. 10, where as Fig. 16 represents a double extraction condensing turbine including process heaters in combination with the HRSG's.

Further, cycle variations can be made with supplementary firing of the HRSG with benefits shown in Fig. 17. Configurations can be varied as shown in Fig. 18.

ABB AVAILABLE LARGE GT'S

The ABB series of GT's represent a family of single shaft machines with external combustor, Fig. 19 provides the range, however, as can be seen only two sizes 45 MW and 80 MW GT 8 and GT 11 are available for the 60 Hz market. Fig. 20 is a typical cross section representing the basic machine configuration.

Unique to ABB design GT's are the single rotor, single burner, and single combustor concept, Fig. 21. The GT 8 rotor welded up from separate forgings is illustrated in Fig. 22. There are no mechanical joints or bolting, no wheel or disc selection keyed to a shaft. Unique in design and maintenance free.

COGEN APPLICATION

It will be difficult to review the many and varied applications of Cogen, so one such unit will be illustrated. "Almere" CC Plant for district heating Fig. 23, 24, 25, and 26 illustrate plant layout and configuration of special note is that the two prime movers GT and ST drive one double ended generator. Fig. 27 is the cycle diagram while GT HRSG ST performance is represented in Fig. 28, 29, and 30 and the plant performance in Fig. 31 which indicated 88.4% fuel utilizations. Performance synopsis for various ambients is shown in Fig. 32.

To illustrate a separate unique ST application in cogeneration PEGUS-11 CC heating power plant is such. The cycle diagram is Fig. 33 showing a reheat-dual admission controlled extraction condensing turbine, with 3 stages of heaters with the HP heater off the controlled extraction to insure constant hot water temp. over all electrical loads. Fuel utilization is 86% at max. thermal load and 50% + at max. electrical load. Fig. 34 illustrates the ST arrangement.

TYPICAL COSTS

Typical costs for various type plants are illustrated in Fig. 35. They vary from 200 $/KW for simple cycle GT's to 1100 $/KW and above (or unknown) for nuclear plants.

All power plants have some environmental impact, and CC plants would minimize these, as can be seen that many plants are in urban areas. Fig. 36 shows pollution control points, thermal noise and flue gas while Fig. 37 shows controlled emissions of a NG fuel CC plant.

After all is said and done the energy production costs are the final concern and Fig. 38 illustrates those elements effecting electricity production costs - Thermal energy can equally be incorporated.

FUTURE POWER PLANT SYSTEMS

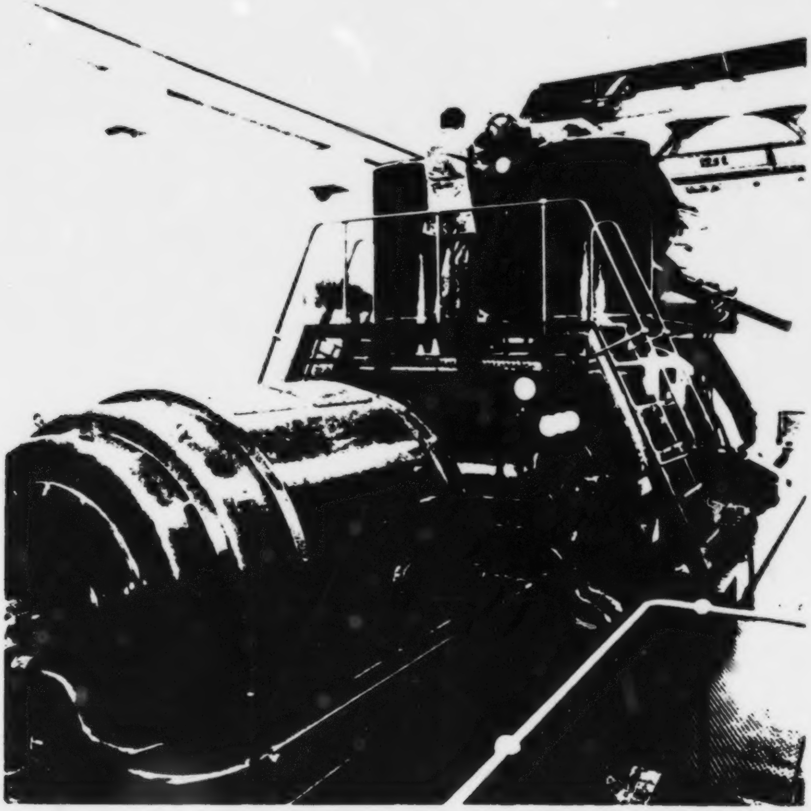
Future power plant systems will have many preconditions as identified in Fig. 39 and it is clear that advantages provided by gas fired CC cogen plants will meet these preconditions Fig. 40

With the many variables of the energy production market, dispersed power plants whether cogen, industrial process, or district heat, or IPP, the CC plant becomes one of the economic answers.

Thank you for your attention.

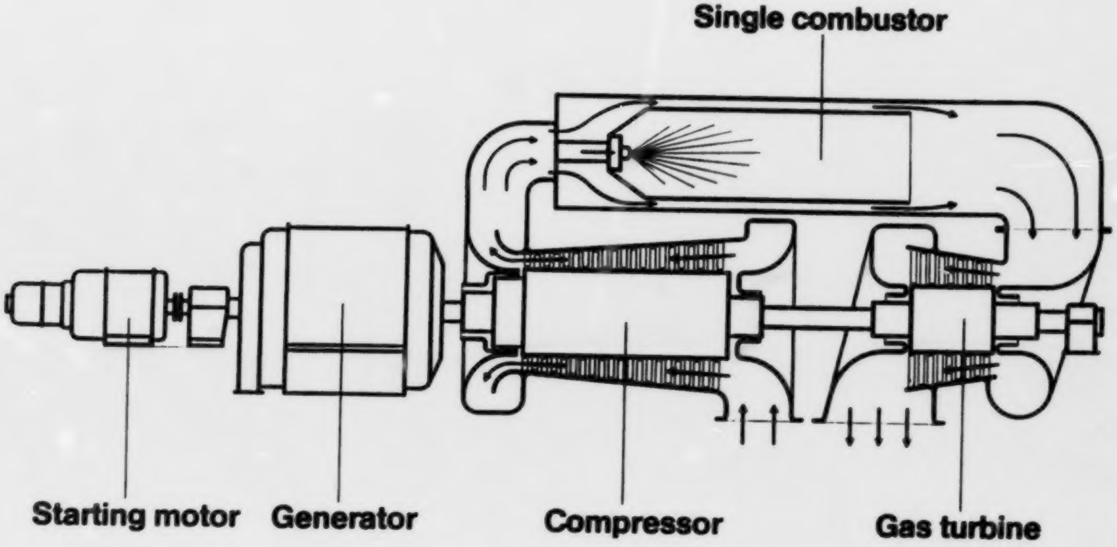
THE END

The world's first industrial gas turbine set at Neuchâtel (1939)



HTCV 02/01/01/F7

The world's first industrial gas turbine set at Neuchâtel (1939)


Single combustor
Starting motor
Generator
Compressor
Gas turbine

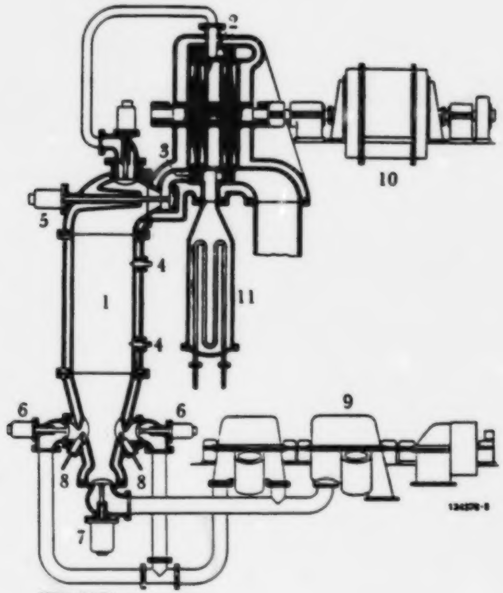
Layout of the single-stage gas turbine set without recuperator

HTCV 02/01/01/F9

FIG. 1

Schematic diagram of the Holzwarth explosion turbine (1910)

FIG. 2



In this machine combustion took place at constant volume

1 — Explosion chamber
2 — Curtis wheels of the turbine
3 — Nozzle
4 — Spark plugs
5 — Nozzle valves
6 — Air valve
7 — Scavenging valve
8 — Fuel injector nozzles
9 — Compressor driven by steam turbine
10 — Generator
11 — Heat exchanger

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BBC
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Gas Turbine Cycle

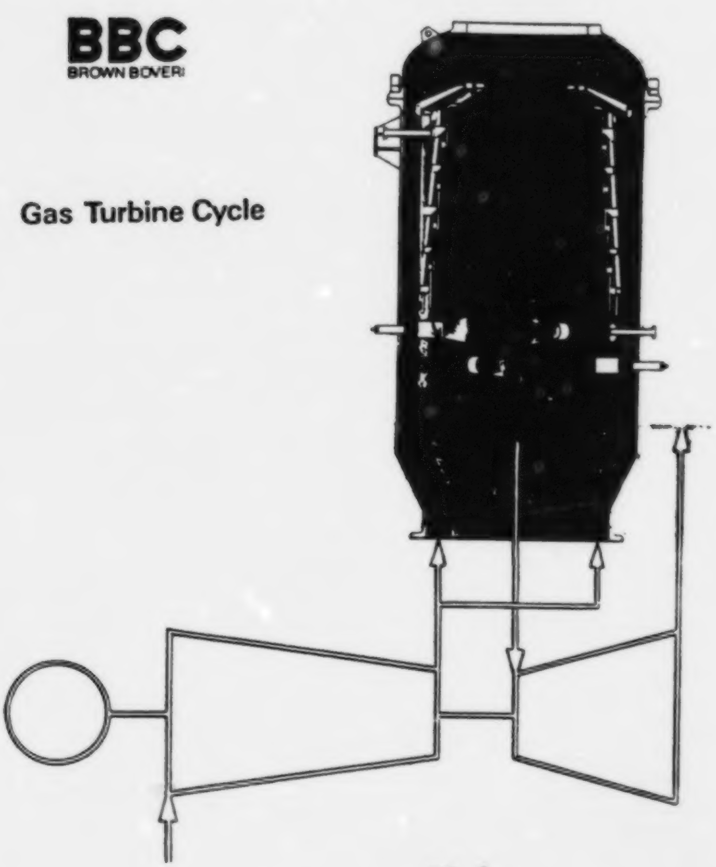
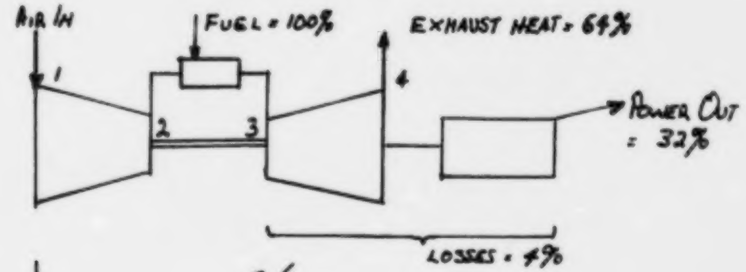
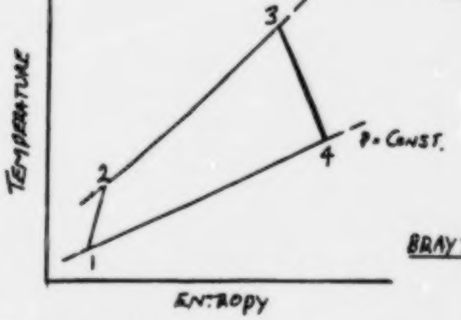


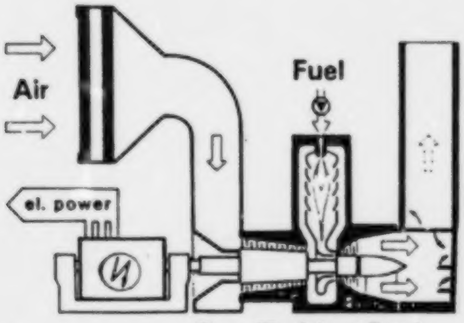
FIG. 3

SIMPLE CYCLE


AIR IN
FUEL = 100%
EXHAUST HEAT = 64%
1
2
3
4
POWER OUT = 32%
LOSSES = 4%

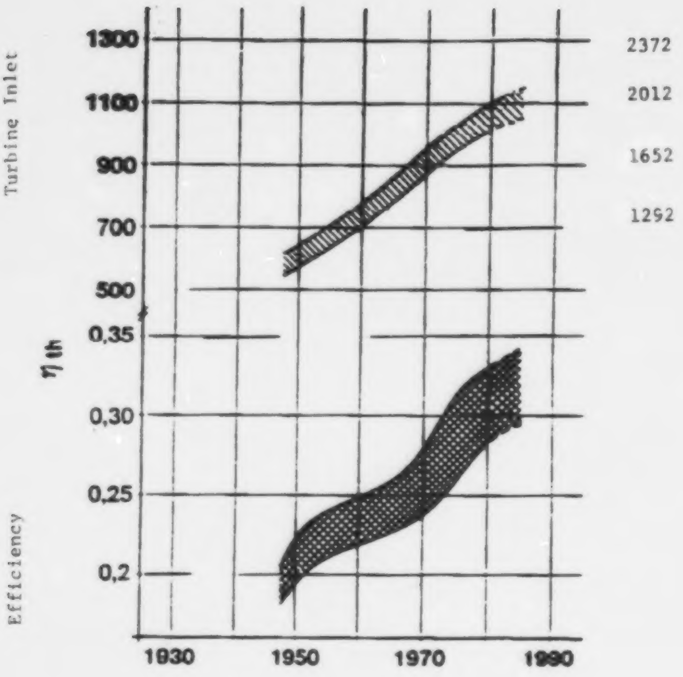

TEMPERATURE
ENTROPY
1
2
3
4
p = CONST.

BRAYTON CYCLE DIAGRAM


Air
Fuel
el. power

Gas Turbine Cycle

FIG. 4



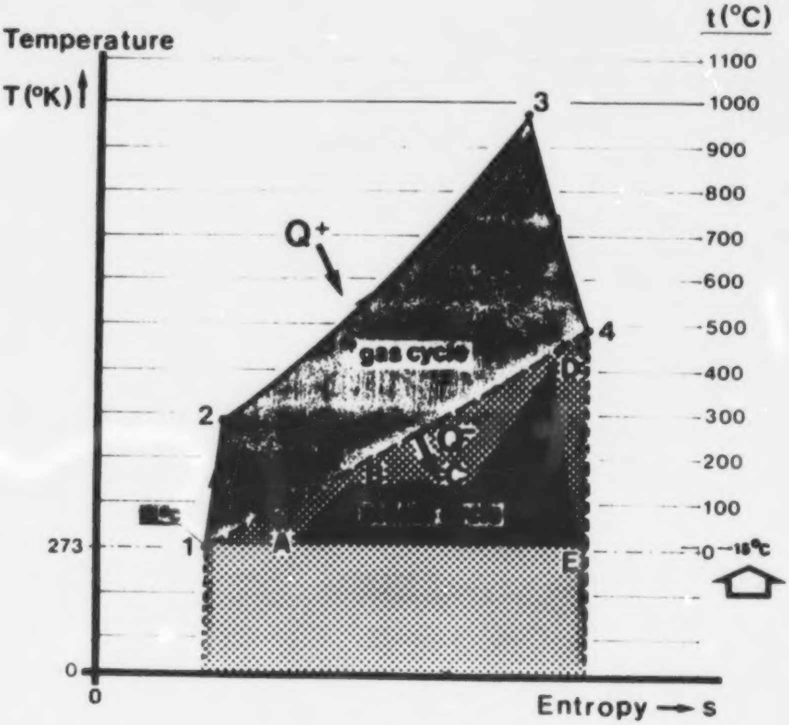
BBC

Development of Gas Turbine Inlet Temperatures and Efficiencies

GK

FIG. 5

The combined gas/steam turbine process in the Temperature-Entropy diagram



(diagram for demonstration purpose only)

FIG. 6

Combined-Cycle Power Plant Principle

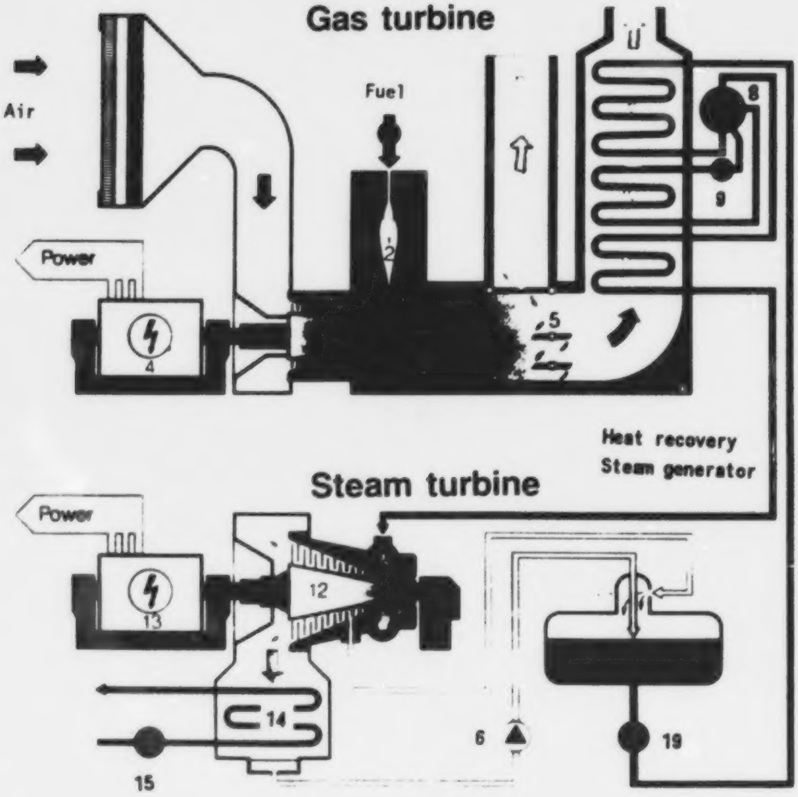
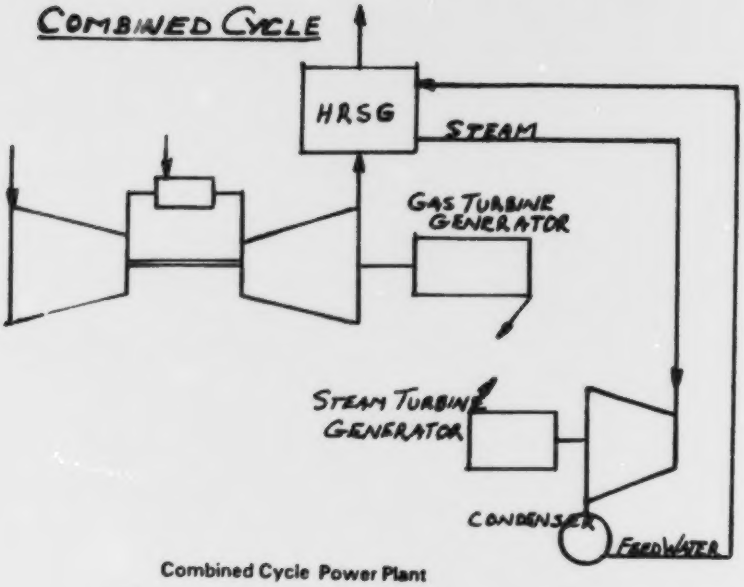

Gas turbine
Air
Fuel
2
Power
4
5
8
9
11
Heat recovery
Steam generator
Steam turbine
Power
12
13
14
15
6
19

FIG. 7

HTGK
13204 E

COMBINED CYCLE


HRSG
STEAM
GAS TURBINE GENERATOR
STEAM TURBINE GENERATOR
CONDENSER
FEEDWATER

Combined Cycle Power Plant

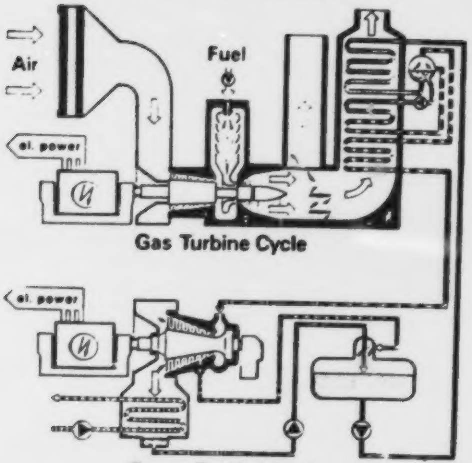

Air
Fuel
el. power
Gas Turbine Cycle
el. power
Steam Turbine Cycle

FIG 7. A.

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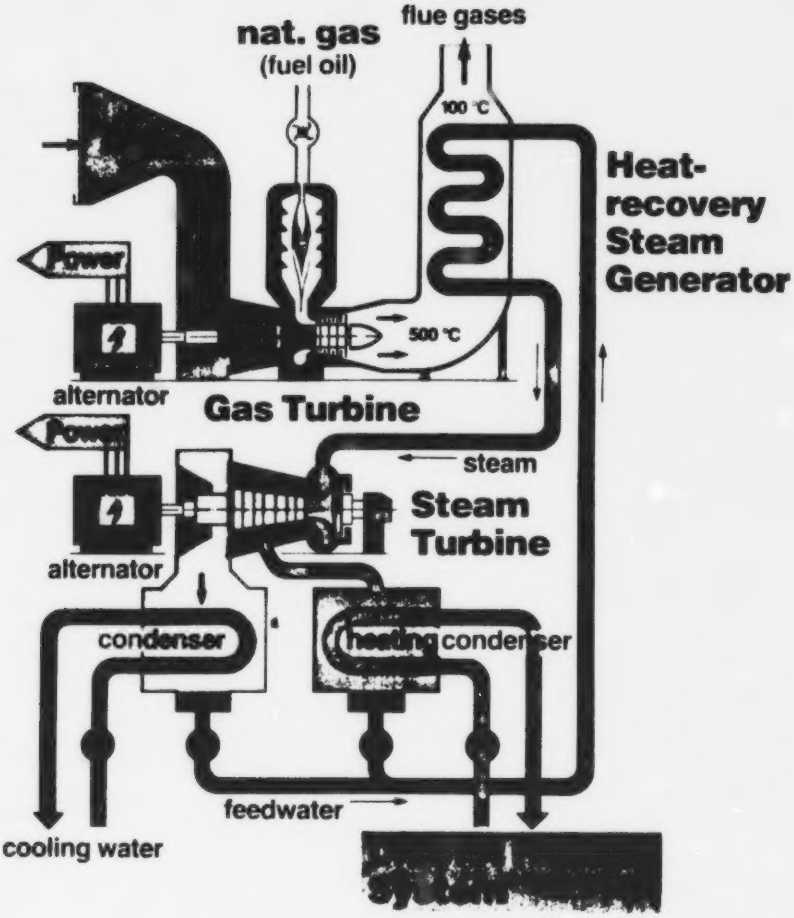
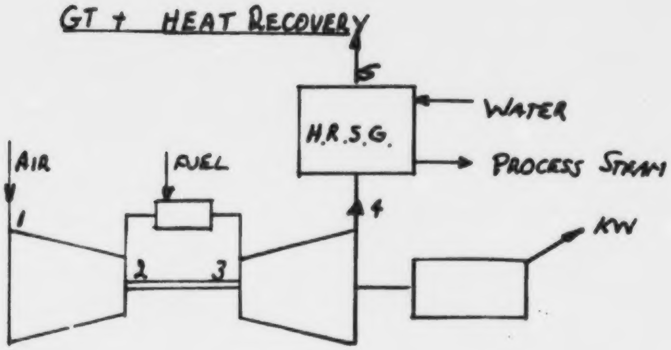
Cogeneration


flue gases
nat. gas
(fuel oil)
100 °C
Heat-recovery Steam Generator
Power
500 °C
alternator
Gas Turbine
Power
steam
Steam Turbine
alternator
condenser
heating condenser
feedwater
cooling water
system

Combined-Cycle Heating Power Plants

HTGK
14019E

FIG. 8


GT + HEAT RECOVERY
5
WATER
H.R.S.G.
PROCESS STEAM
AIR
FUEL
1
4
KW
2
3

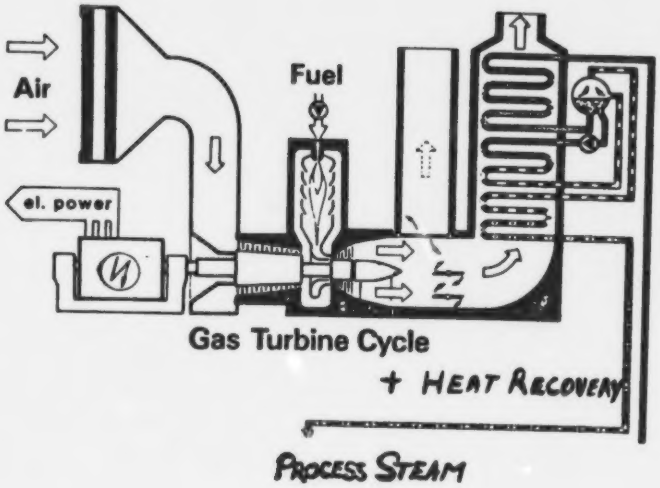

Air
Fuel
el. power
Gas Turbine Cycle
+ HEAT RECOVERY
PROCESS STEAM

FIG 8A.

BBC
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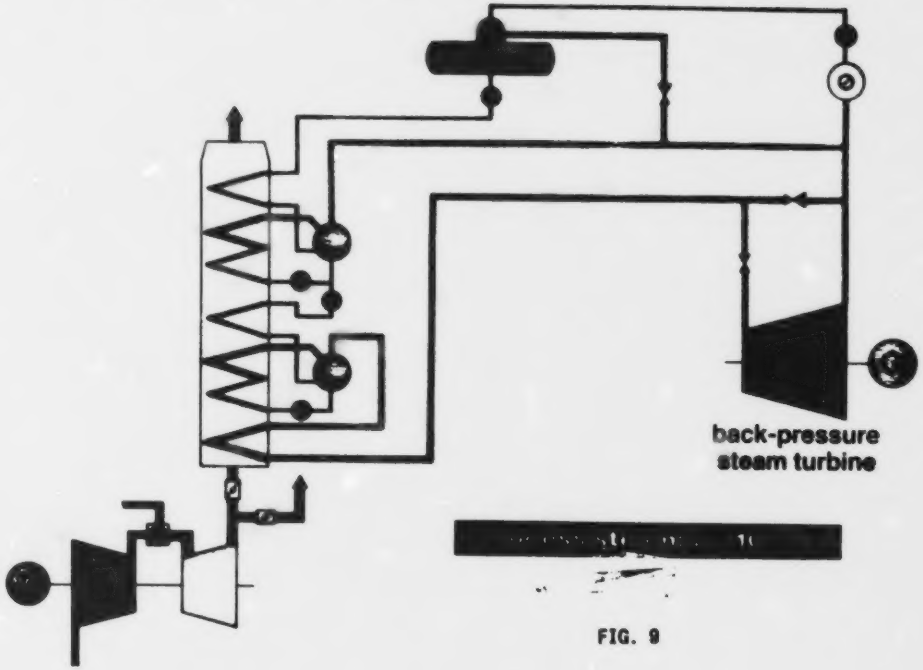
Cogeneration

Combined-Cycle Plant for Industry

HTGK
14046 E


back-pressure
steam turbine

[redacted]

FIG. 9

BBC
BROWN BOVERI

HTGK
14047 E

Cogeneration

Combined-Cycle Plant for Industry

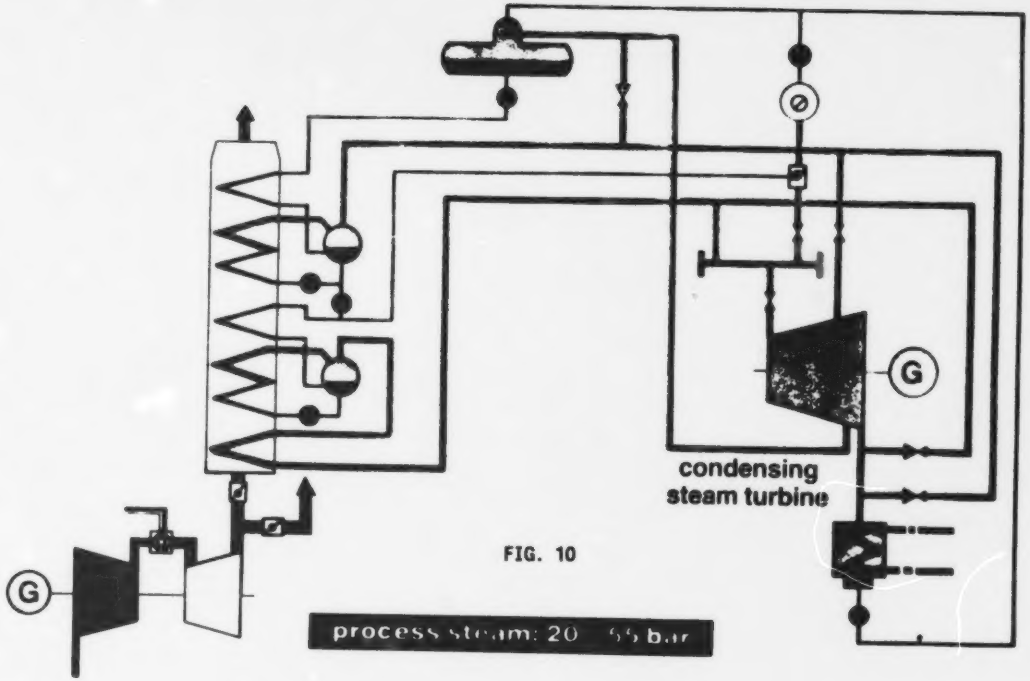
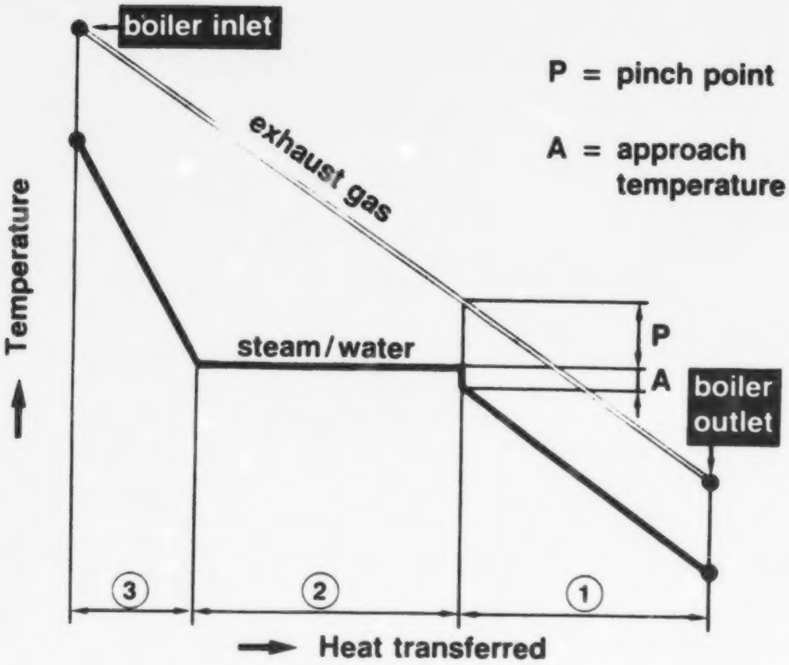

G
condensing
steam turbine
G

FIG. 10

process steam: 20 55 bar

Heat Transfer
Heat Recovery Steam Generator
(single-pressure system)

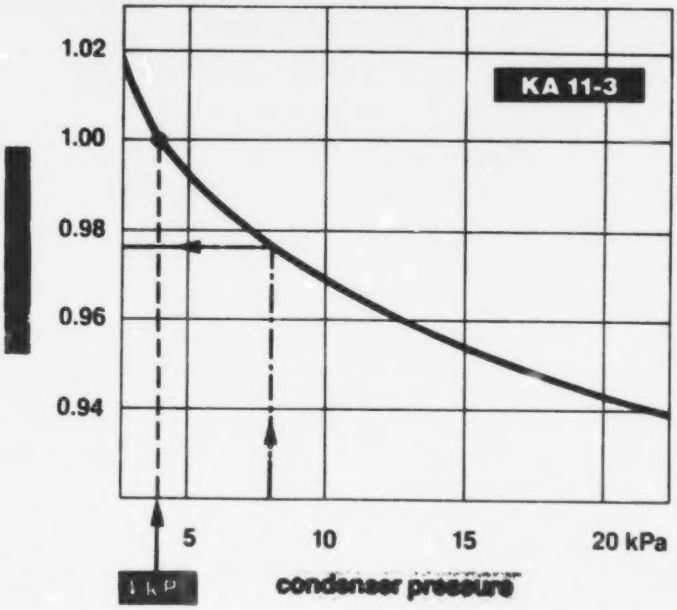

boiler inlet
P = pinch point
A = approach temperature
exhaust gas
Temperature
steam/water
P
A
boiler outlet
③
②
①
Heat transferred

① economizer
② evaporator
③ superheater

FIG. 11

[illegible] output [illegible]

if pressure in the condenser of the steam turbine deviates from 4 kPa



[illegible]

FIG. 12

BBC Combined-Cycle Plants

BROWN BOVERI

[redacted]

if air temperature deviates from 15 °C

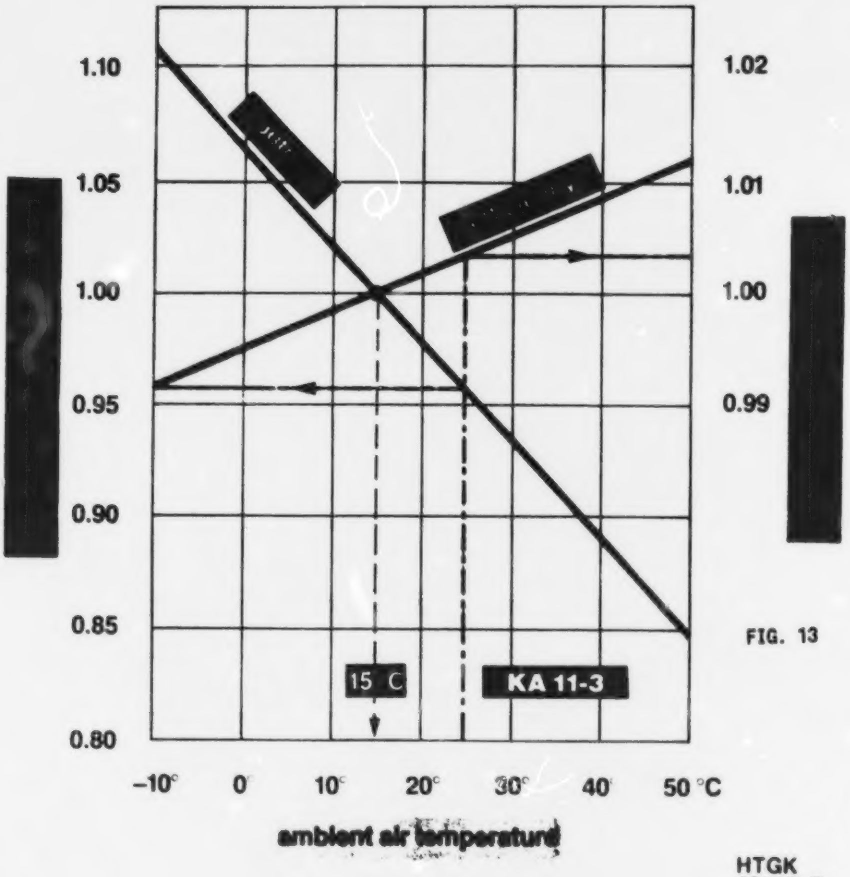


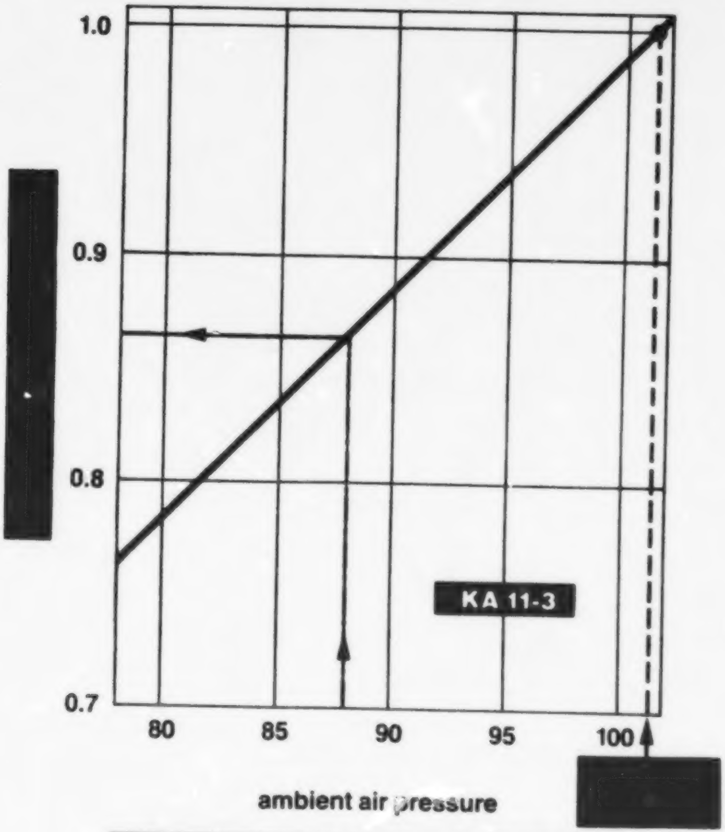
FIG. 13

HTGK
13115 E

BBC Combined-Cycle Plants

[redacted]

if air pressure deviates from 101.3 kPa



[redacted]

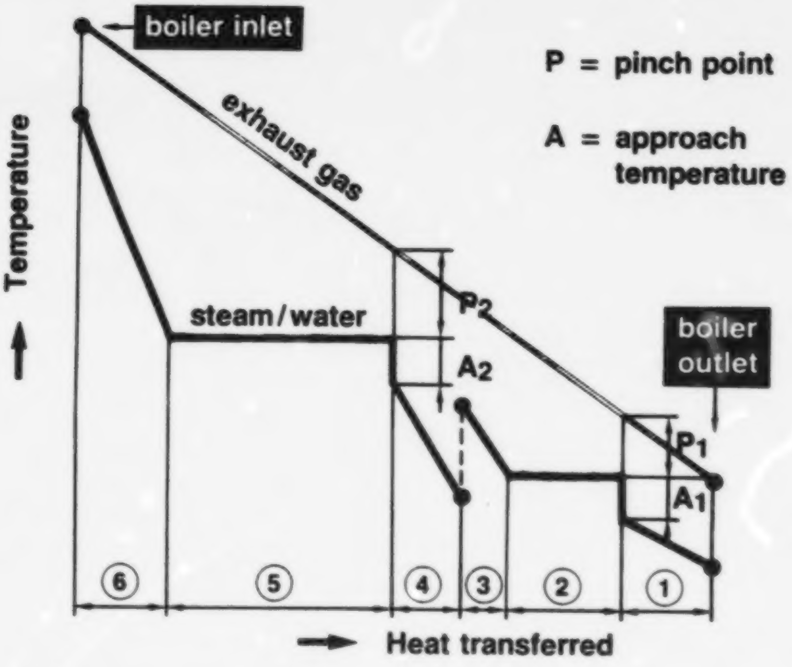
[redacted]

air pressure does not affect efficiency

FIG. 14

HTGK
13114 E

Heat Transfer
Heat Recovery Steam Generator
(dual-pressure system)


boiler inlet
P = pinch point
A = approach temperature
exhaust gas
Temperature
steam / water
P2
A2
boiler outlet
P1
A1
⑥
⑤
④
③
②
①
Heat transferred

- ④ HP-economizer
- ⑤ HP-evaporator
- ⑥ HP-superheater
- ① LP-economizer
- ② LP-evaporator
- ③ LP-superheater

FIG. 15

HTGK
13170 E

BBC
BROWN BOVERI

Cogeneration

HTGK
14048 E

Combined-Cycle Cogeneration Power Plant

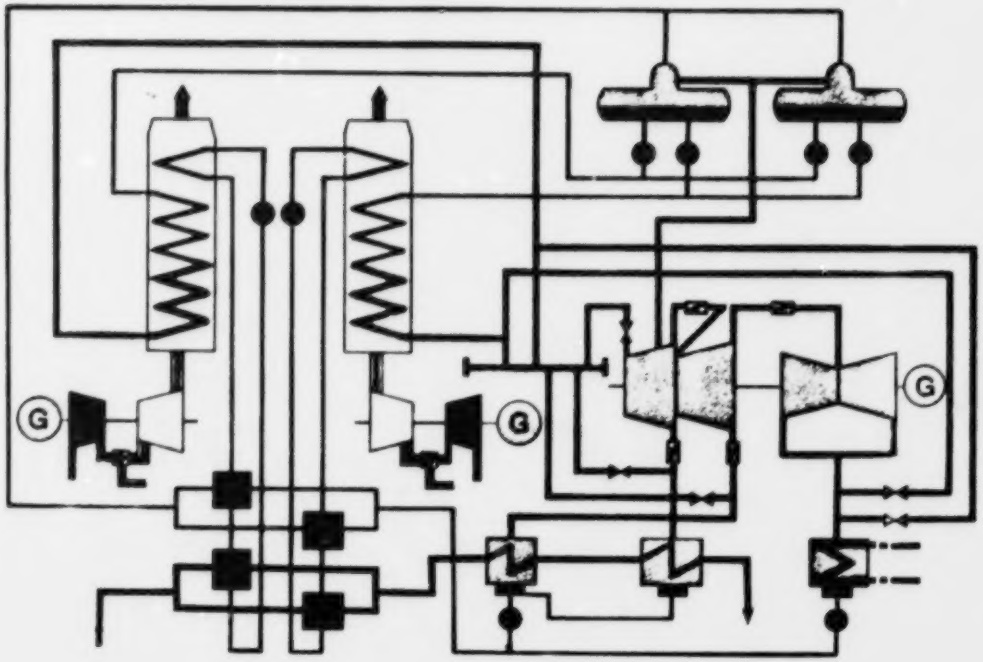


FIG. 16

Application of Supplementary Firing

- ► High efficiency
- ► Increase of output
  - – constantly
  - – for short period
- ► Fluctuating operation
- ► Compensation of derating due to ambient conditions

FIG. 17

HTMV
13032 E

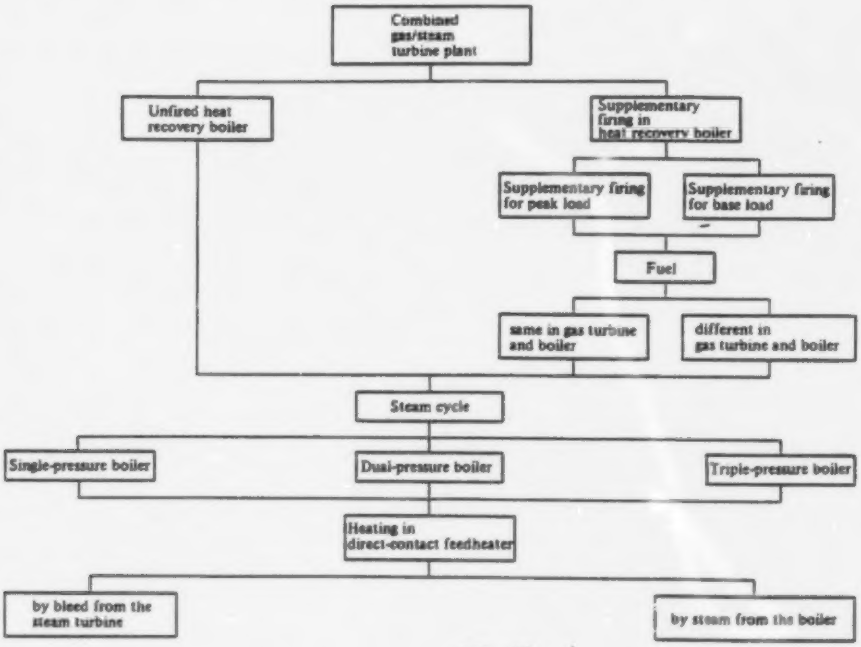
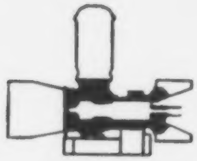

Combined gas/steam turbine plant
Unfired heat recovery boiler
Supplementary firing in heat recovery boiler
Supplementary firing for peak load
Supplementary firing for base load
Fuel
same in gas turbine and boiler
different in gas turbine and boiler
Steam cycle
Single-pressure boiler
Dual-pressure boiler
Triple-pressure boiler
Heating in direct-contact feedheater
by bleed from the steam turbine
by steam from the boiler

FIG. 18

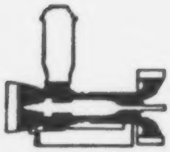
Variants of the combined gas/steam turbine plant

BBC open-cycle gas turbines



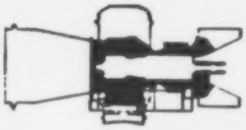
Type 9 **50/60 Hz**

Rated output: 35–38 MW
Thermal efficiency: 28.9%
Shaft speed: approx. 4500 rpm



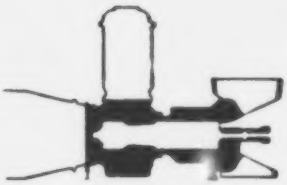
Type 8 **50/60 Hz**

Rated output: 46–50 MW
Thermal efficiency: 32%
Shaft speed: approx. 6300 rpm



Type 11 **50/60 Hz**

Rated output: 72–82 MW
Thermal efficiency: 31.7%
Shaft speed: 3600 rpm



Type 13 **50 Hz**
Type 13E **50 Hz**

Rated output: 91–100 MW
142–155 MW
Thermal efficiency: 32.6%
33.7%
Shaft speed: 3000 rpm
3000 rpm

FIG 19

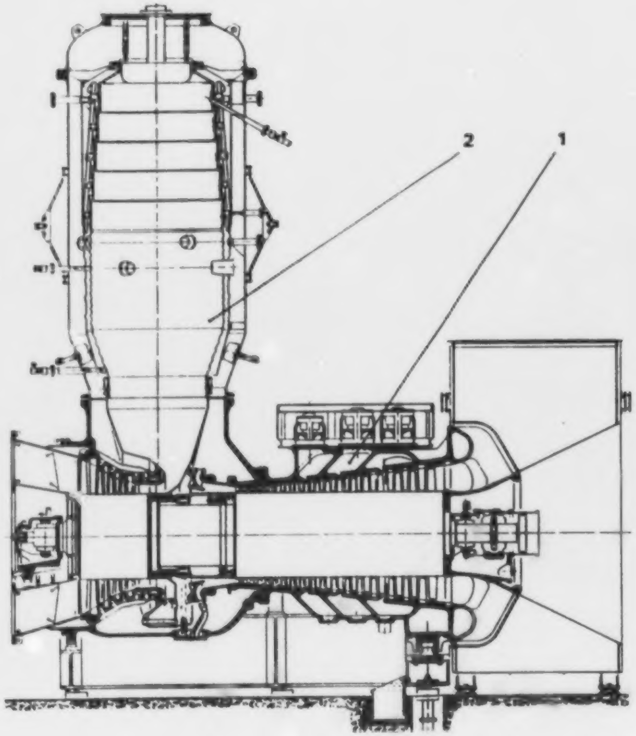


FIG 20.

1 Thermischer Block
2 Brennkammer

1 Thermal block
2 Combustion chamber

1 Bloque térmico
2 Cámara de combustión

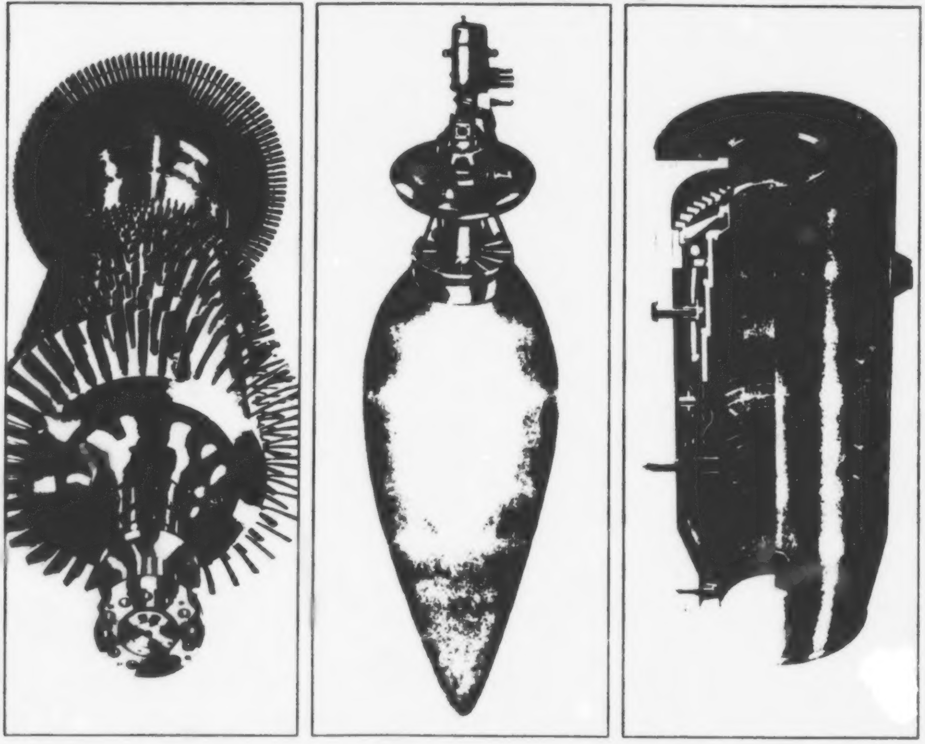
1 Bloc thermique
2 Chambre de combustion

Thermischer Block mit Brennkammer
Thermal Block with Combustion chamber
Bloque térmico con la camara de combustion
Bloc thermique avec la chambre de combustion

Originated from : HTCT 711 [illegible]	
Supersedes :	
Superseded by :	
Drawn	[illegible]
Checked	[illegible]

BBC GT Type 11 HTCV 110 24

Brown Boveri gas turbines for simplicity. Rated 20 MW and above



**One rotor. One burner.
One combustion chamber.**

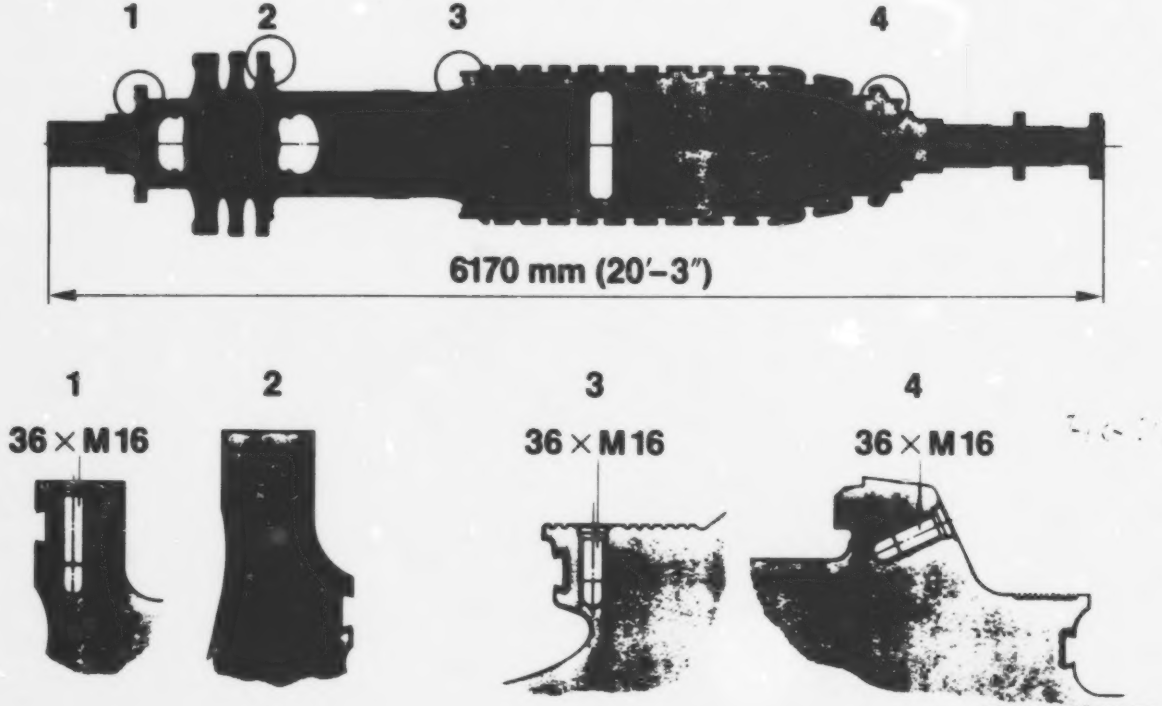
Fig 31

BBC
BROWN BOVERI

Gas turbine type 8

BBC

Gas turbine rotor/balancing planes


1
2
3
4
6170 mm (20'-3")
1
36 × M16
2
3
36 × M16
4
36 × M16

HTCV 02/02/02/F3

BBC
BROWN BOVERI

Cogeneration

KWGV
14059 E

(CAD drawing)

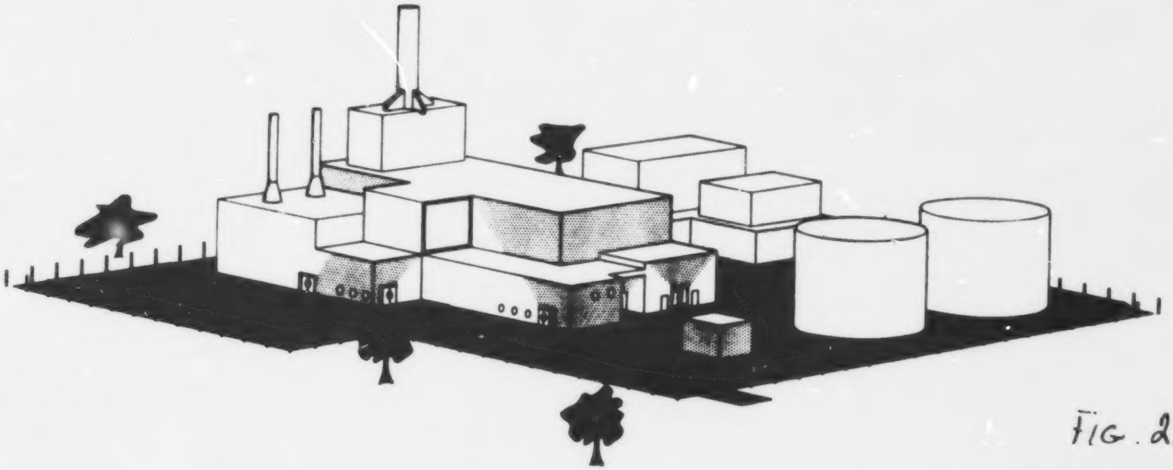
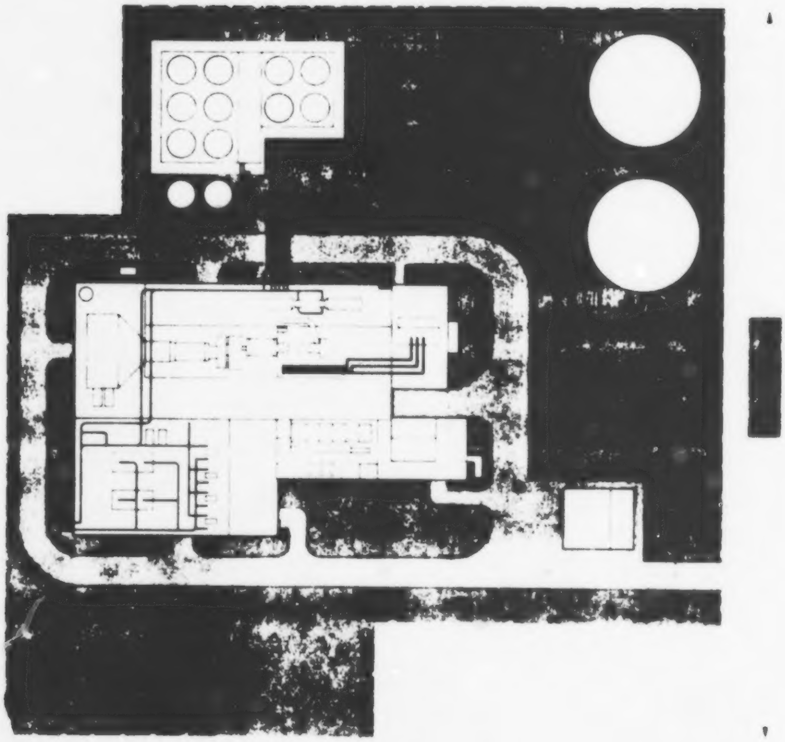


FIG. 23

District Heating Combined-Cycle Plant «Almere»

BBC BROWN BOVERI

Cogeneration



District Heating Combined-Cycle Plant «Almere»

70 MW$_e$/240 GJ/h$_{th}$

FIG. 24

KWGV
1406CE

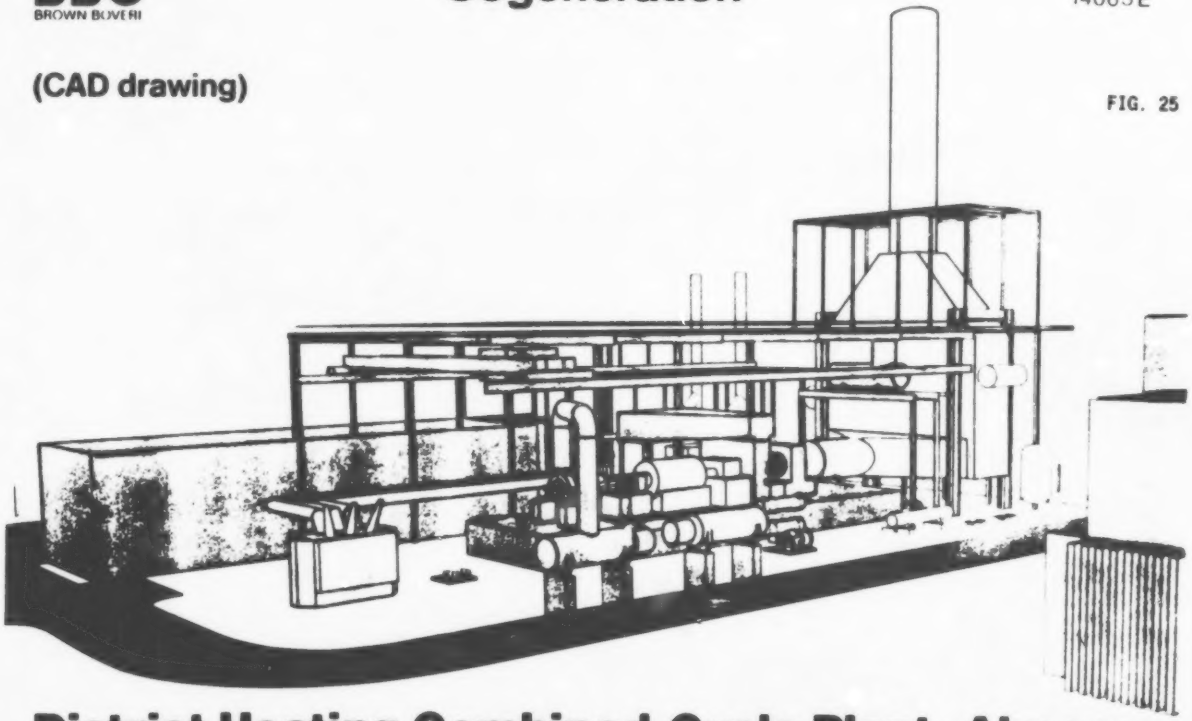
BBC
BROWN BOVERI

Cogeneration

KWGV
14063E

(CAD drawing)

FIG. 25



District Heating Combined-Cycle Plant «Almere»

BBC
BROWN BOVERI

KWGV
14062 E

Cogeneration

single-shaft unit arrangement

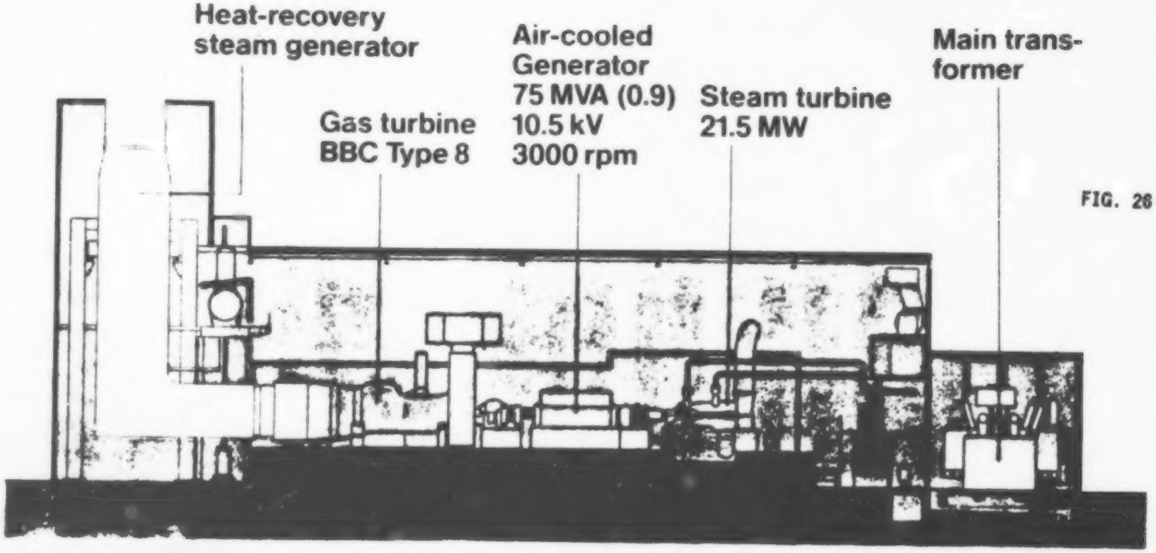

Heat-recovery steam generator
Gas turbine BBC Type 8
Air-cooled Generator 75 MVA (0.9) 10.5 kV 3000 rpm
Steam turbine 21.5 MW
Main transformer

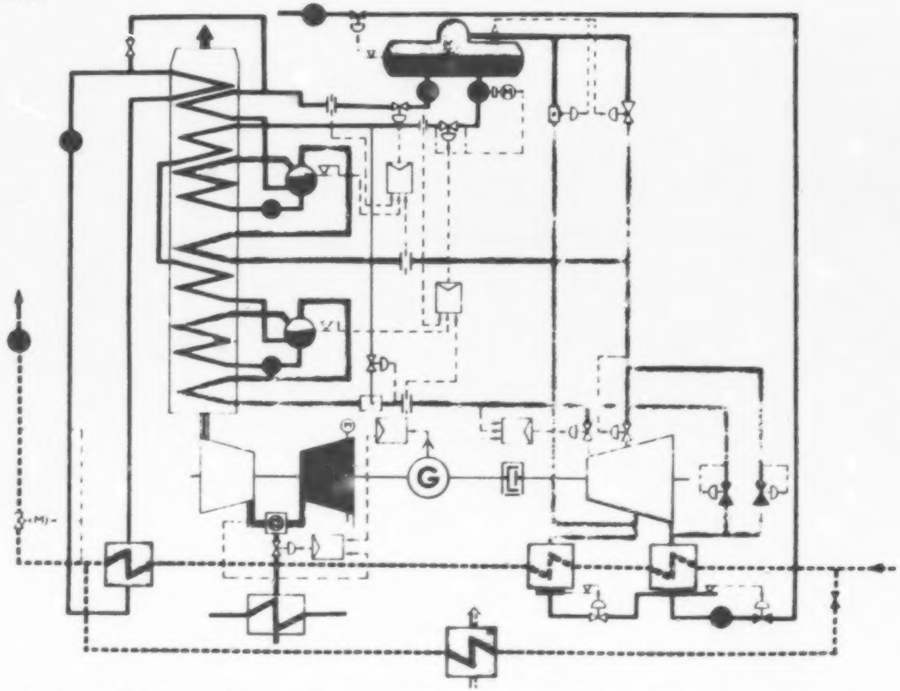
FIG. 28

District Heating Combined-Cycle Plant «Almere»

BBC
BROWN BOVERI

Cogeneration

KWGV
14053 E



District Heating Combined-Cycle Plant “Almere“

BBC
BROWN BOVERI

Cogeneration

Combined-Cycle Plant «Almere»

Gas turbine unit:

Gas turbine model		BBC Type 8
Air – ambient pressure	bar	1.01
– ambient temperat.	°C	[illegible]
Fuel	–	nat. gas
Exhaust gas flow	kg/	18
Exhaust gas temperat.	°C	523
Power input (nat. gas)	MW	151.5
Power output at shaft	MW	49.2
Thermal efficiency	%	32.5

At base-load operating conditions

Power factor	0.8
Air humitidy	80%

FIG 28

KWGV
14055 E

BBC Cogeneration

Combined-Cycle Plant «Almere»

Heat-recovery steam generator*:

Inlet [illegible]	[illegible]mperature	°[illegible]	523
[illegible]	[illegible]mperatur[illegible]	[illegible]	[illegible]
[illegible]	[illegible]mperatur[illegible]	[illegible]	[illegible]
LP s[illegible]	– temperatur[illegible]	[illegible]	[illegible]
	– pressure	[illegible]	[illegible]
	– massflow	[illegible]	[illegible]
H[illegible]	– temperatur[illegible]	[illegible]	47[illegible]
	– pressure	bar	50.3
	– massflow	kg/s	22.2
Aux. [illegible] recovery circu[illegible]	– inlet temp[illegible]	°C	84.5
	– outlet temp[illegible]	°C	10.5
	– heat transfer	MW	7.4

* Supplier: HCG
NEM Boiler Division
Leiden/NL

KWGV
14056 E

BBC
BROWN BOVERI

Cogeneration

Combined-Cycle Plant «Almere»

Steam turbine-generator:

Turbine type (BBC mod. DGHHZ-9048)		dual-pressure extraction/ back-pressure	
HP steam	– temperature	°C	472
	– pressure	bar	48.7
	– massflow	kg/s	22.2
LP steam	– temperature	°C	229
	– pressure	bar	6.4
	– massflow	kg/s	4.6
Extraction 1 (to h. exch. 1)	– temperature	°C	65.8
	– pressure	bar	0.26
	– massflow	kg/s	13.0
Extraction 2 (to h. exch. 2)	– temperature	°C	82.7
	– pressure	bar	0.53
	– massflow	kg/s	13.5
Power output at shaft		MW	21.4

At gas turbine base-load

[illegible]

KWGV
14057 E

BBC
BROWN BOVERI

Cogeneration

Combined-Cycle Plant «Almere»

Plant overall data:

Power input (nat. gas)		MW	151.5
Power output of generator		MW	69.3
Heating output	– h. exch. 1	MW	28.8
	– h. exch. 2	MW	28.4
	– h. exch. 3	MW	7.4
	total	MW	64.6
Total power and heating output		MW	133.9
Power/heat-ratio			1.07
Electrical efficiency		%	[illegible]5.7
Fuel utilization rate		%	88.4

Ambient: 1.013 bar
6°C
80 % (rel.)

* gross

KWGV
14054 E

BBC Cogeneration KWGV 14058 E

CHP Combined-Cycle Plant «Almere»

GT load C	Air temp. C	Heating water temp. °C in	out	Fuel input MW	Power output MW	Heating output MW	Electr. effic. % *	Fuel utilizat. %
base	+35	50.0	91.4	133.3	58.9	23.6	44.2	61.9
base	+16	50.0	97.0	145.4	65.0	62.5	44.7	87.8
peak 104.6%	+15	[illegible]	105.0	151.1	66.4	6.6	44.0	48.3
base	+10	42.0	77.3	149.2	68.6	64.9	46.0	89.5
base	+ 6	[illegible]	85.0	151.5	69.3	64.6	45.7	88.4
base	0	50.0	85.4	155.7	70.0	65.3	45.4	87.4
base	[illegible]	[illegible]	[illegible]	155.7	69.8	64.3	44.8	86.2
peak 107.9%	0	50.0	97.0	166.0	75.5	67.9	45.5	86.4
base	-10	[illegible]	[illegible]	162.6	72.4	65.4	44.5	87.8
base	-10	55.0	120.0	162.6	69.3	64.7	42.6	82.4
base	-18	[illegible]	[illegible]	169.1	75.2	66.6	44.5	83.9

Synopsis of Performance

(* gross)

BBC
BROWN BOVERI

Cogeneration

KWGV
14065E

223 MW_{el} / 188 MW_{th} (677 GJ / h)
51.7 % / 85.8 % (net)

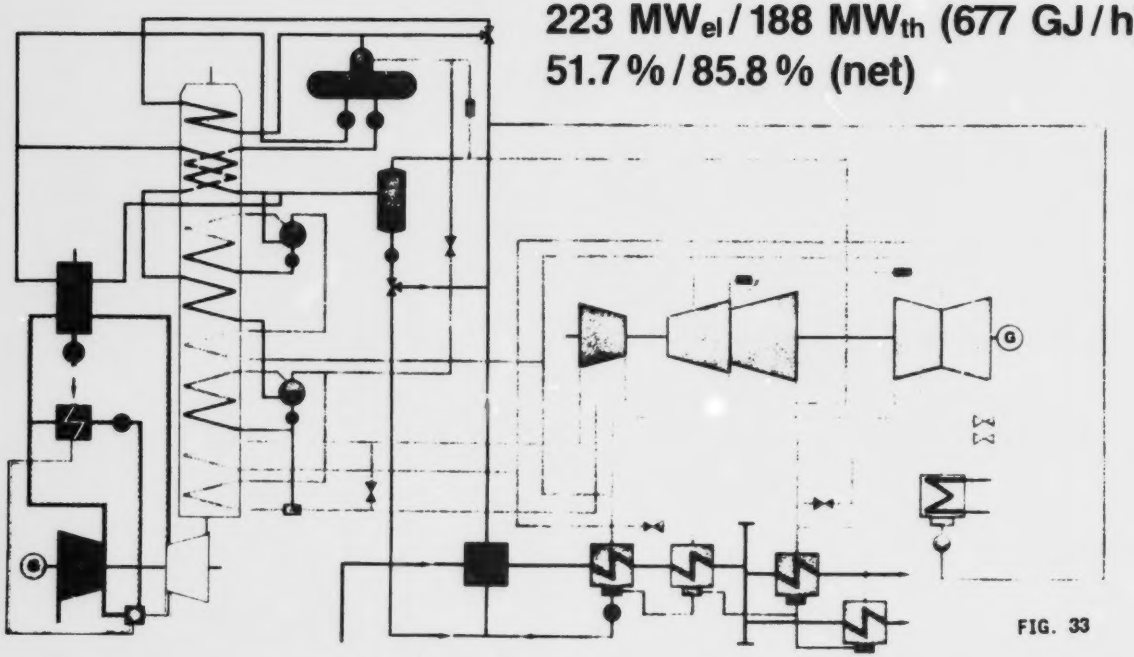


FIG. 33

PEGUS-12 Combined-Cycle Heating Power Plant

BBC
BROWN BOVERI

Cogeneration

HTGK
14024E

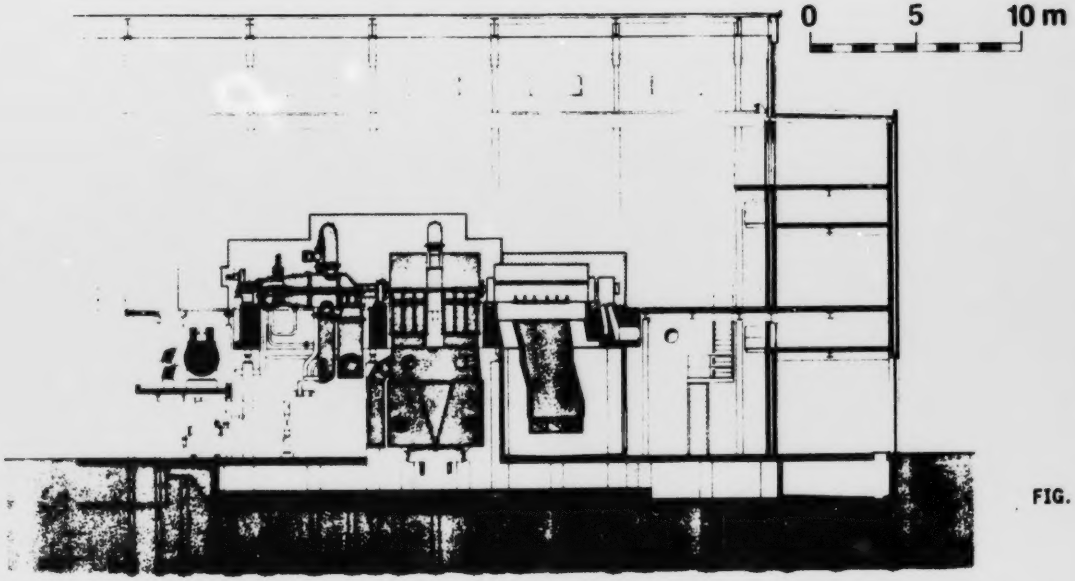


FIG. 34

PEGUS-11 Combined-Cycle Heating Power Plant

BBC BROWN BOVERI

Combined – cycle plants

HTMV
13010 E

Plant cost of different power plant types

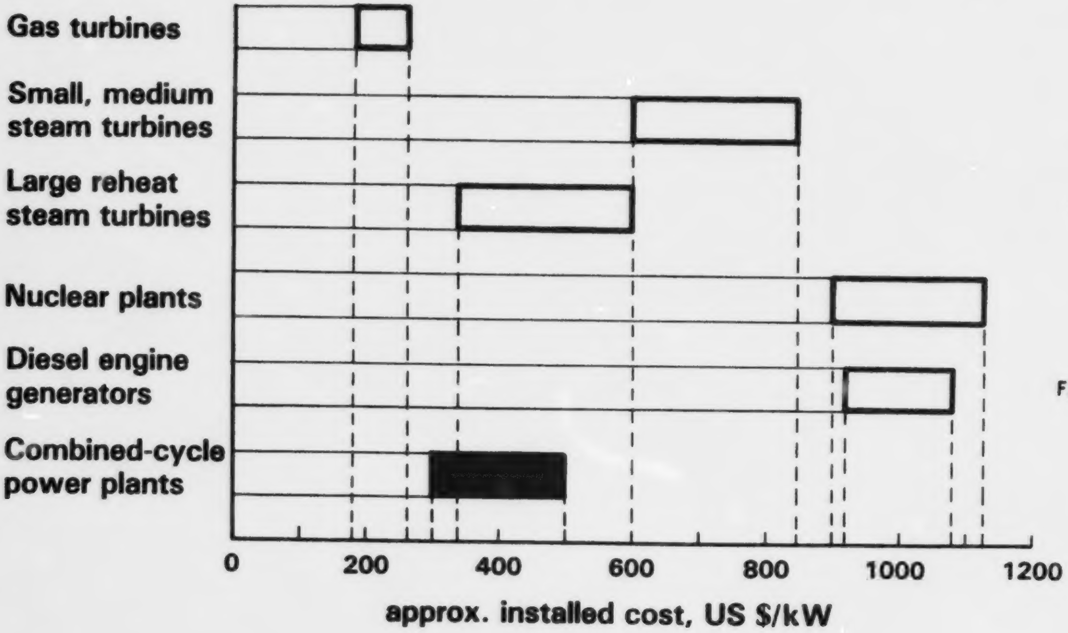
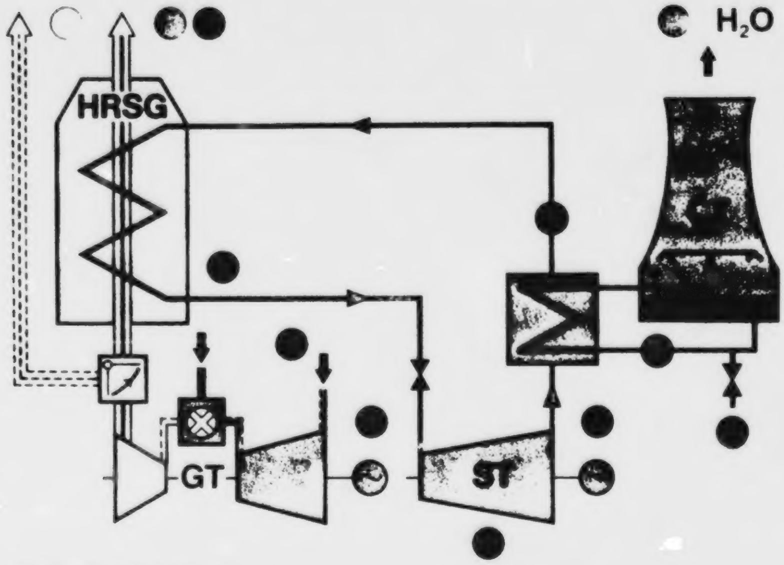


FIG. 35

BBC Combined-Cycle Plants
BROWN BOVERI

Impact on the Environment



● Noise > 40 dB

Flue gas: SO_2, NO_x, CO, UHC, (H_2O)

◌ Waste heat

◐ Waste waters

FIG. 36

HTGK
13136 E

BBC
BROWN BOVERI

Cogeneration

Emissions of a Combined-Cycle Plant with NO_x Control

Emissions	with steam injection into combustor	with catalyst (SCR system) and steam injection
NO_x	**75 vppm** (EPA-US standard)	**10 vppm** (California)
CO	**10 vppm**	**10 vppm**
HC_x	**5 vppm**	**5 vppm**
SO_x	**0.07 vppm**	**0.07 vppm**
Particles	**1.5 g/m^3**	**1.5 g/m^3**

Fuel: nat. gas (S max. 3.4 mg/Nm^3)

FIG. 37

14029E

BBC Thermal Power Plants
BROWN BOVERI

Electricity Production Cost

$Y_{EL} =$ (1) [redacted] + (2) $\frac{Y_F}{\eta}$ + (3) [redacted]

(1) ———> Capital Cost

(2) ———> Fuel Cost

(3) ———> Operating and maintenance costs

Y_{EL}	= specific production cost	\$/kWh
I	= total investment cost	\$
P	= nominal power plant output	kW
h	= equiv. utilization period	h/a
Y_F	= specific fuel cost	\$/kWh
η	= efficiency of power generation	kW/kW
U	= constant operating cost	\$/a
U'	= variable operating cost	\$/kWh
ψ'	= annuity factor $\frac{q^n \cdot (q-1)}{(q^n-1)}$	1/a
q	= $(1+z)$	
z	= rate of interest	%/100
n	= amortization period	a

10 001 E

FIG. 38

Future Power Plant Systems

Preconditions:

- Short completion time
- Highest efficiency
- Lowest first cost
- Availability of fuel
- Politically acceptable
- Lowest possible emissions and impact on the environment
- Proven technology
- Aptitude for cycling operation
- Potential for further development

[illegible] GK
10007 E

BBC
BROWN BOVERI

Cogeneration

Gas fired Combined-Cycle Power Plants for District Heating

ADVANTAGES:

▷ Low first cost.

▶ Short construction time.

▷ Highest efficiency of all thermal power generating systems.

▶ Lowest additional outlay for fuel to produce the heating energy.

▷ Most economical utilization of natural gas due to cogeneration.

▶ Maximum environmental compatibility. Low SO_2, NO_X and UHC emission levels. No ash.

▷ Decentralized plants installed close to consumers are possible.

▶ No noise emission outside plant.

▷ Best operational flexibility.

▶ High reliability of equipment.

▷ High level of automation.

▶ High availability.

A Cost Effective and Flexible Industrial Cogeneration System

By
Phil H. Schneider
Solar Turbines Inc.

5

COGEN SYSTEM WITH IMPROVED COST EFFECTIVENESS AND FLEXIBILITY

1. This presentation is about industrial cogeneration, and in particular, a new combined-cycle cogeneration system which offers improved cost effectiveness and flexibility of operation

   There is a brief background to illustrate how Solar fits into the cogeneration business, then a description of two recently developed components which provide unique improvements to the cogen system, and finally a discussion on various configurations of the system and the benefits each offers.

2. Solar Turbines Inc. is a subsidiary of the Caterpillar company.

   Solar manufactures industrial gas turbine engines. Over the past 35 years, Solar has sold some 7000 engines throughout the world. Most of them have been packaged either as compressor sets or generator sets. Solar makes the 800 kW Saturn engine, the 3 to 4 MW Centaur engine and the 8 to 9 MW Mars engine. In addition, Solar packages the ASEA STAL GT-35 (a 15 to 16 MW engine), and markets it in North America as the Jupiter engine.

   In 1973, the oil embargo made everyone more aware of the value of fossil fuels. Most engine manufacturers increased their efforts to develop more efficient engine systems. Solar began developing both combined-cycle and cogeneration systems, incorporating a proprietary once through steam generator.

3. This is a simple schematic diagram of a combined-cycle plant. Exhaust heat from the gas turbine is recovered in a heat recovery steam generator or HRSG. The steam drives a steam turbine which adds power to the electric generator. The electrical output of this plant may be 30 to 50% greater than for the simple cycle plant, with no additional fuel burned. Electric conversion efficiencies often exceed 40%.

   Large combined-cycle plants have been employed successfully by the utilities for some time. Smaller industrial-sized systems have not fared as well due to relative system complexity, and higher installed costs.

   Solar set goals to simplify these systems and bring down the installed costs (due to economies of scale).

4. The primary area that needed simplification was the steam generation system. Conventional heat recovery boilers have separate economizer, evaporator, and superheater sections. The boiler section has a large separating drum, requiring level controls and constant blowdown to maintain water quality. They require a deaerating feedwater heater to remove oxygen, and chemical injection to control pH level and scavenge the residual oxygen. This is done to prevent corrosion of the carbon steel materials. These units cannot be operated dry (without steam being generated) so a large bypass stack and damper valves are required to isolate the HRSG if it is desirable to operate the gas turbine while the steam system is down.

5. Solar has developed a very simple once-through steam generator for heat recovery applications. It requires no separating drums, level controls, blowdown, or chemical injection. As the figure illustrates the HRSG consists of a series of tubes in a serpentine array. Feedwater enters one end and superheated steam exits the other end. There are no physical boundaries between the economizer, evaporator, and superheater sections.

   Metal corrosion is not a problem because the tubes are made of a corrosion resistant nickel alloy. Water quality is maintained by demineralizing (or polishing) in the feedwater system. Because of the alloy tubing, the HRSG can be operated dry at gas turbine exhaust temperatures, so no bypass stack or damper valves are required.

6. The once through steam generator is simple, with no drums, level controls, blowdown, or bypass. It has a large turndown range because with no physical boundaries between the sections, the superheater length can expand or contract at various load levels. The corrosion resistant alloy provides long life and reduced maintenance. No chemical addition is required. The HRSG is inherently safe due to the lack of a drum, and the small amount of energy storage. And these HRSG's are factory assembled and easily shipped.

7. This photo illustrates the simple serpentine heat transfer matrix of these HRSG's, and shows the range of sizes we've produced. The small one operates on a 1200 kW diesel combined cycle, and the larger one is in test behind a General Electric Frame 7 engine at an electric utility.

8. This is a photo of the combined-cycle development test facility. In the far corner is a Centaur 3 MW gas turbine engine. The insulated cube is the HRSG, and the steam turbine is to the left.
9. Two of these powerplants were installed in a gas processing plant in Oklahoma in 1982. Since then these units have accumulated over 40,000 hours of operation with steam system availability of about 99%. The once through HRSG has proven to be very durable and trouble free.

10. Now, on to cogeneration. In the late 1970's the U.S. Congress passed legislation making industrial cogeneration more feasible economically. The utilities were required to sell gas to qualified facilities and purchase* electric power. But, cogeneration still suffers from the same economies of scale problem as does the combined-cycle. This plot of installed cost in $/kW on the vertical axis and MW output on the horizontal axis illustrate the point. Several very large units, the order of 100 MW were installed by large chemical companies at very reasonable cost. The absolute values of cost appear low because they are U.S. dollars, and the data is a few years old now. The point is, in smaller sizes needed by industrial sites, the costs are relatively higher, making the economics marginal.

*their expenses

11. Solar set an objective to improve the economics of industrial cogeneration to stimulate further implementation. We set out to reduce the installed cost, to increase the operating efficiency-in terms of overall fuel utilization efficiency, part load performance, and operating flexibility. We want to provide high reliability and availability, and reduce operating and maintenance costs.

12. Solar can now offer this system based on the "new steam" approach. A key component with respect to reliability, availability, and reduced maintenance is the once through steam generator, with its corrosion resistant materials and passive water treatment.

    The economics are largely driven by increased performance which is due to higher efficiency steam cycles, with supplementary firing, and a new steam turbine. These will be discussed shortly.

    Engineering, installation, and commissioning costs are all reduced due to an integrated system of matched components, with each skid factory assembled and tested. The fully automated control system simplifies operation and reduces operating costs.

13. Before continuing with the system discussion, I want to illustrate the benefit of increasing steam pressure and temperature over current industrial practice, and illustrate the steam turbine we've designed to handle it. This slide illustrates the steam cycle efficiency for back pressure steam turbine cycles. It has steam cycle efficiency on the vertical axis and steam pressure on the horizontal axis, for different steam temperatures. This efficiency refers to just the power extracted from the back pressure steam turbine, In addition, the steam gets all the thermal energy in the steam sent to the process, plus the electrical power form the gas turbine generator set. For these calculations, the steam back pressure was maintained at 166 psig, and the feedwater temperature was 160°F.

    Current standard industrial practice is for a steam pressure of 600 psi and 700°F, and the steam cycle is 11% efficient. Maximum current practice is 900 psi and 900°F. This is usually employed in larger systems, and the cycle efficiency increases to 15%. Solar's near term system will be available next year, and it operates on steam at 1050°F and 1300 psi. It has an efficiency of nearly 19%. This is a significant increase over current practice.

14. This next figure illustrates what that means in terms of incremental electric power. It is a plot of electrical output from the back pressure steam turbine only vs. process steam flow.

    Currently available back pressure steam turbines fall within the shaded bands, with the smaller single stage machines typically running on 700°F steam, and the larger multistage machines running at temperatures from 750 to 900°F. The upper line shows the output of the new 1050°F turbine. For example, if one has an industrial site that needs 100,000 pph of process steam, a conventional topping turbine may provide 3 to 3-1/2 MW of power. The new turbine will provide 4-1/2 MW. This additional MW becomes quite significant in the economic analysis of the system.

15. This figure is a cross section through the new back pressure steam turbine. There is not time to go into all the design features, but it is a compact two stage steam turbine, employing many features of our gas turbine engines. It is capable of running efficiently on 1050°F steam, over a wide range of steam flowrates. It is capable of rapid starts and load changes encountered in cogeneration applications. This turbine is being developed with co-funding from the Gas Research Institute.

    The steam turbine is mated to a production gas turbine reduction gearbox. It reduces the 15,000 rpm turbine shaft speed to 1800 rpm for the generator. This 5 MW turbine is about six feet long and just over two feet in diameter.

16. Now I'll get on with discussion of the cogeneration system. I'm going to show you a series of figures of cogeneration systems based on our Mars 8.6 MW engine. At the top is a simple schematic of the system. The plot has thermal energy in thousands of pounds per hour of process steam on the vertical axis, and electric output in MW on the horizontal axis. The shaded area represents the portion of this energy plane that the system can service cost effectively.

    This first figure shows a simple cycle gas turbine engine, with an HRSG generating saturated steam for the thermal process. This is a fairly common industrial cogen system.

    For the simple cycle Mars engine with HRSG, the electrical output is limited to 8.6 MW and peak steam production is 40,000 pph. As the engine power is reduced, so is steam production. The lower boundary is based on economic return, below which the system is not justified.

17. The first improvement made to the baseline system is supplementary firing. By adding a duct burner, the turbine exhaust gas can be heated to 1800°F (or higher) before entering the HRSG. This hotter gas allows three times the steam production, and the powerplant operates cost effectively over the shaded region shown.

18. Benefits of supplemental firing include: The 3-fold increase in steam production. Overall fuel efficiency is increased because all the heat added by the burner produces useful thermal energy. The burner provides an effective means of modulating thermal output to follow the demand, while allowing the gas turbine to operate at rated power-for good efficiency and long life. The specific cost of thermal production is reduced because the duct burner is a relatively inexpensive component, and steam production is increased so much. This increases the return on investment as will be shown in a few minutes.

19. The next improvement offered is the back pressure steam turbine. The HRSG is uprated to produce high pressure superheated steam which is expanded in the turbine on its way to the process. The addition of the turbine allows the system to operate in this shaded region. At full duct firing, the steam turbine adds 4.8 MW to the electrical output, so the total plant output increases to 13.4 MW. The broken line at the bottom of the triangle is the operating line when all the steam passes through the turbine enroute to the process. If the site cannot use all the electrical power for a given thermal requirement, and it is not economical to export power, steam can be bypassed around the turbine, reducing electrical output. This causes the plant to operate to the left of the broken line.

20. Benefits of adding the back pressure steam are: Additional electricity is generated at a very low incremental heat rate (less than 4000 bfu per kwh). All of the heat added to superheat the steam is recovered by the turbine and turned to electricity. Specific cost in terms of $/kW is reduced because the back pressure steam turbine is less costly than the rest of the system, thereby reducing the average cost per kW. The system is flexible because both thermal output and electric to thermal ratio can be varied without modulating the gas turbine. All these features contribute to a better economic return for the owner.

21. This diagram shows a variation on the system. For situations where electric demand is high, but for brief periods there is reduced thermal demand, a small condenser can be added in parallel with the process. This allows reduction of thermal output below the operating line.

22. The final option is the addition of a low pressure or condensing steam turbine, and valving to allow extraction from the crossover piping. All the steam passes through the back pressure turbine, and steam not required for the process is expanded in the condensing turbine to make additional electricity. With this system, the operating region extends all the way to the x-axis, where we have zero extraction to the process. Maximum electrical output increases to 20 MW.

23. The benefits of the extraction version of the system are: It provides the maximum flexibility between electrical and thermal output. It's especially good where there is high electrical demand and variable thermal demand. It further reduces the installed cost per peak kW, because the low pressure turbine and condenser are less costly (per kW) than the rest of the system. The electrical output and efficiency are maximized.

24. This is a plot of brake thermal efficiency vs shaft power for the combined cycle plant with no steam extraction. I included it to illustrate that the supplementary fired combined cycle offers excellent efficiency over a wide range of power output. This makes it an excellent powerplant for pipeline applications or small power producers.

25. Now we have this energy plane map of regions in which various powerplants operate. What does it mean?

26. We reviewed the Dunn & Bradstreet industrial data base which has energy data on 21,000 industrial sites which expend 90% of the U.S. industrial energy. We imposed minimum criteria on these sites which favored cogeneration, such as annual operating hours > 6000, price of electricity > $.05/kWH, steam demand > 15,000 pph and electric demand of > 4 MW. Some 1000 U.S. sites meet these criteria.

27. This shotgun plot illustrates the stated electrical and thermal demand of these 1000 sites. You can see that there is a wide variation in required electrical to thermal energy ratio.

27 & 25 Now, superimposing these sites on the powerplant map we can see that a significant number of sites fall into each powerplant region. consequently it is necessary to offer all the variations of cogen powerplants in order to satisfy the needs of industry. That is precisely what we offer with the matched set of gas turbines and steam products that are described herein. In addition, Solar offers similar equipment used on the Centaur engine which creates a similar map between 2 and 9 MW electrical output.

28. As a final exercise, the financial return for these powerplants operating within their respective regions were calculated. The calculations were based on the parameters listed here: electricity value of $.06/kWH, gas price of $3.2/MMBTU, and utilization of 95% times 8500 hours.

The contour lines of constant rate of return are shown with the number representing annual percentage return. The absolute values look pretty high, due to the selected conditions, but the relative values are significant. All of the improvement options: the duct firing, the back pressure steam turbine, and the condensing or extraction steam turbine, offer substantial improvements to the economic return compared to the baseline system. Consequently many sites which were marginal or uneconomical for cogeneration will cross the economic threshold and become viable for cogeneration. Secondly, these new components open up a wide region on the energy map to this family of cogeneration systems.

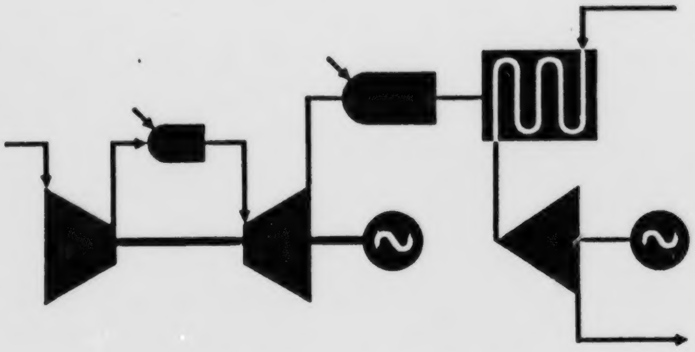
29. This is a plot plan illustration of the new cogeneration system with the back pressure steam turbine. This large skid is the gas turbine generator set. The exhaust is ducted through the duct burner and to the heat recovery steam generator. The steam turbine generator skid is on the right, and there are two ancillary equipment skids for the burner fuel controls and the feedwater treatment and pumping skid. Each skid is factory assembled and tested to reduce installation and checkout costs.

In conclusion, Solar offers a new industrial cogeneration system incorporating newly developed components, and higher steam cycle efficiency. This system provides improved economics and operating flexibility for the cogeneration plant owner.

jy055sch

Phil Schneider
Solar Turbines, Inc.

Cogeneration System with Improved Cost Effectiveness and Flexibility



SOLAR
TURBINES
INCORPORATED

Solar Turbines Incorporated

San Diego, California

Industrial Gas Turbine Engines:

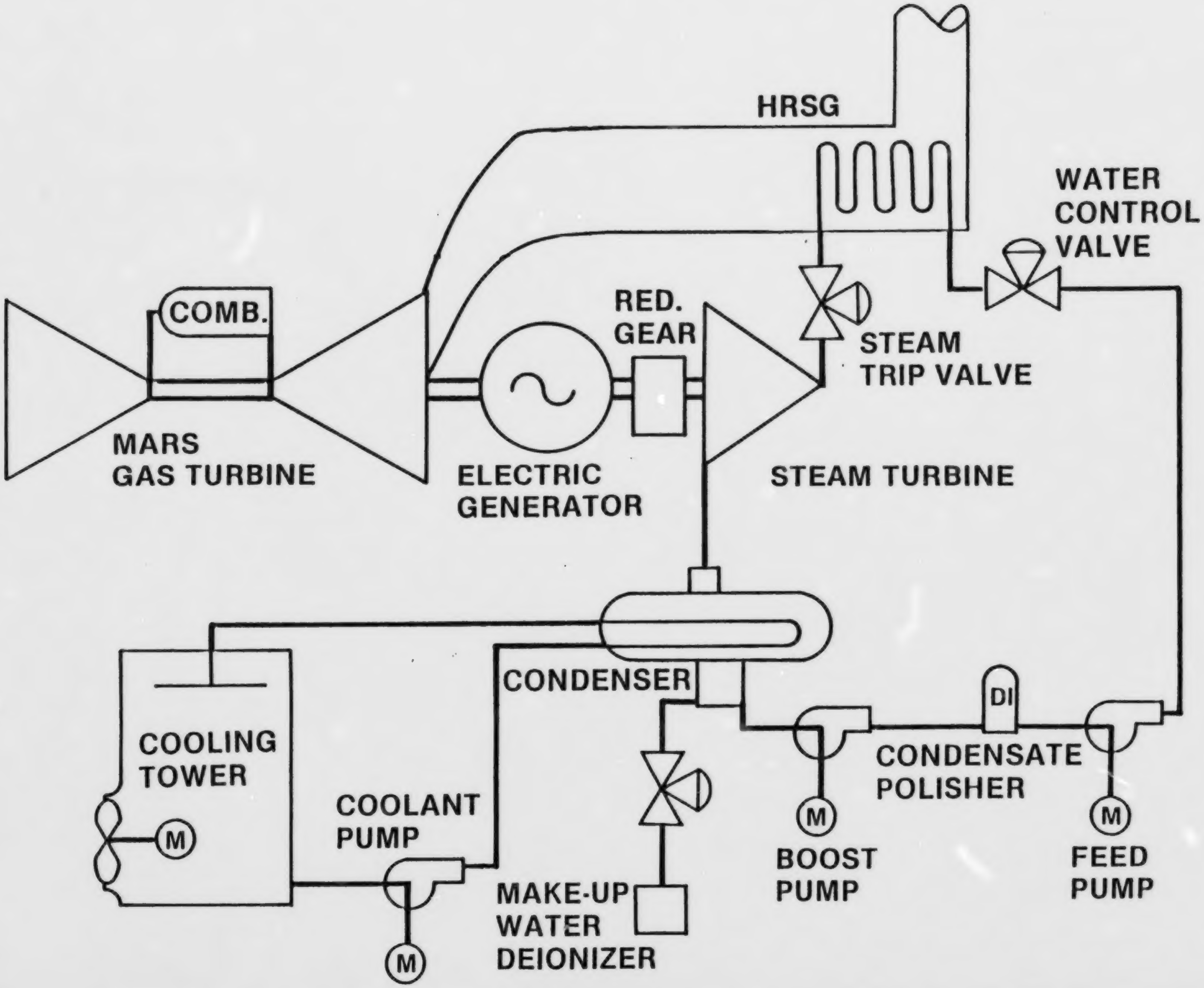
- Saturn - 800 kW
- Centaur - 3,000 to 4,000 kW
- Mars - 8,800 kW
- Jupiter - 16,000 kW

Steam Products:

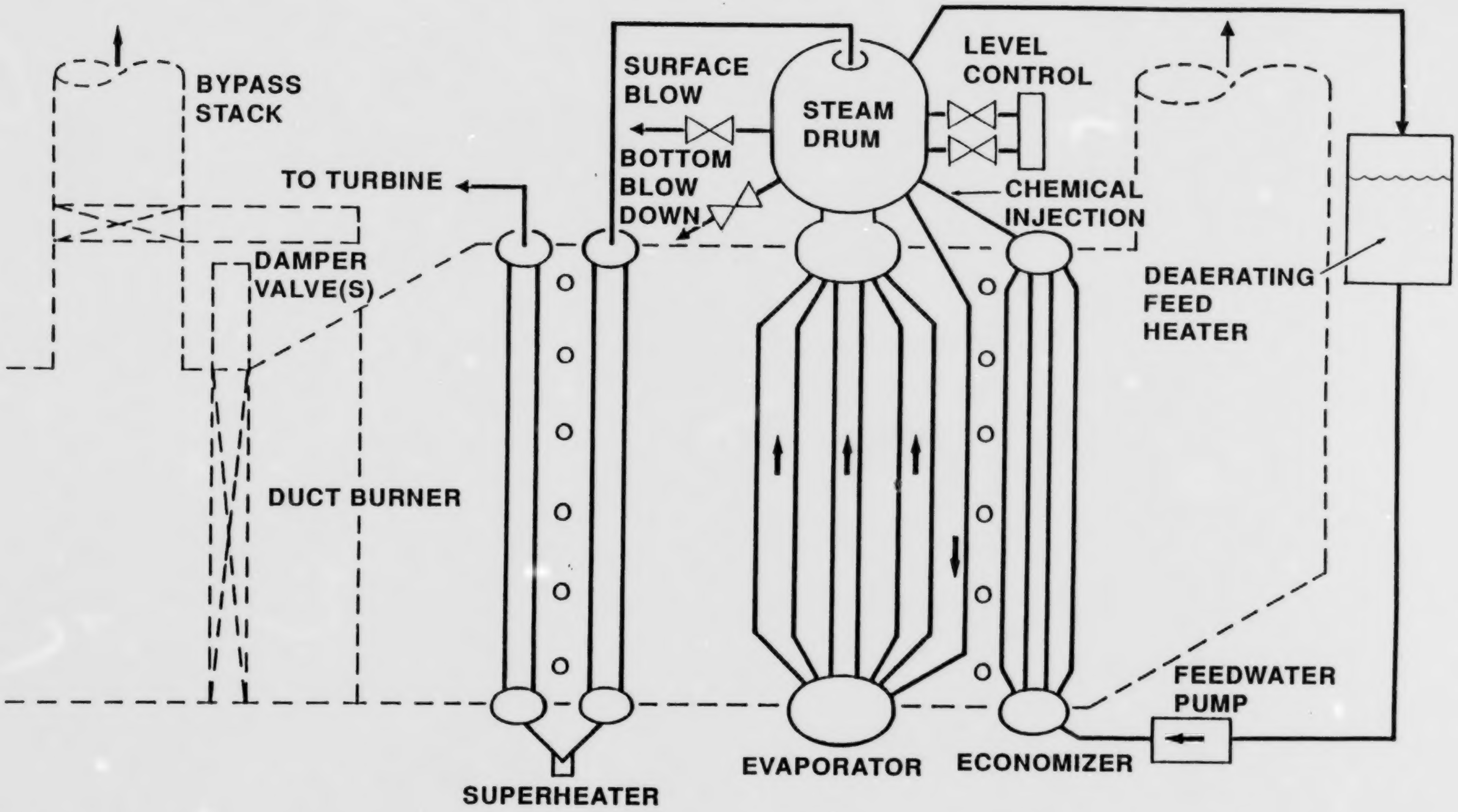
- Once Through Steam Generators
- Combined Cycles
- Cogeneration Systems

SOLAR
TURBINES
INCORPORATED

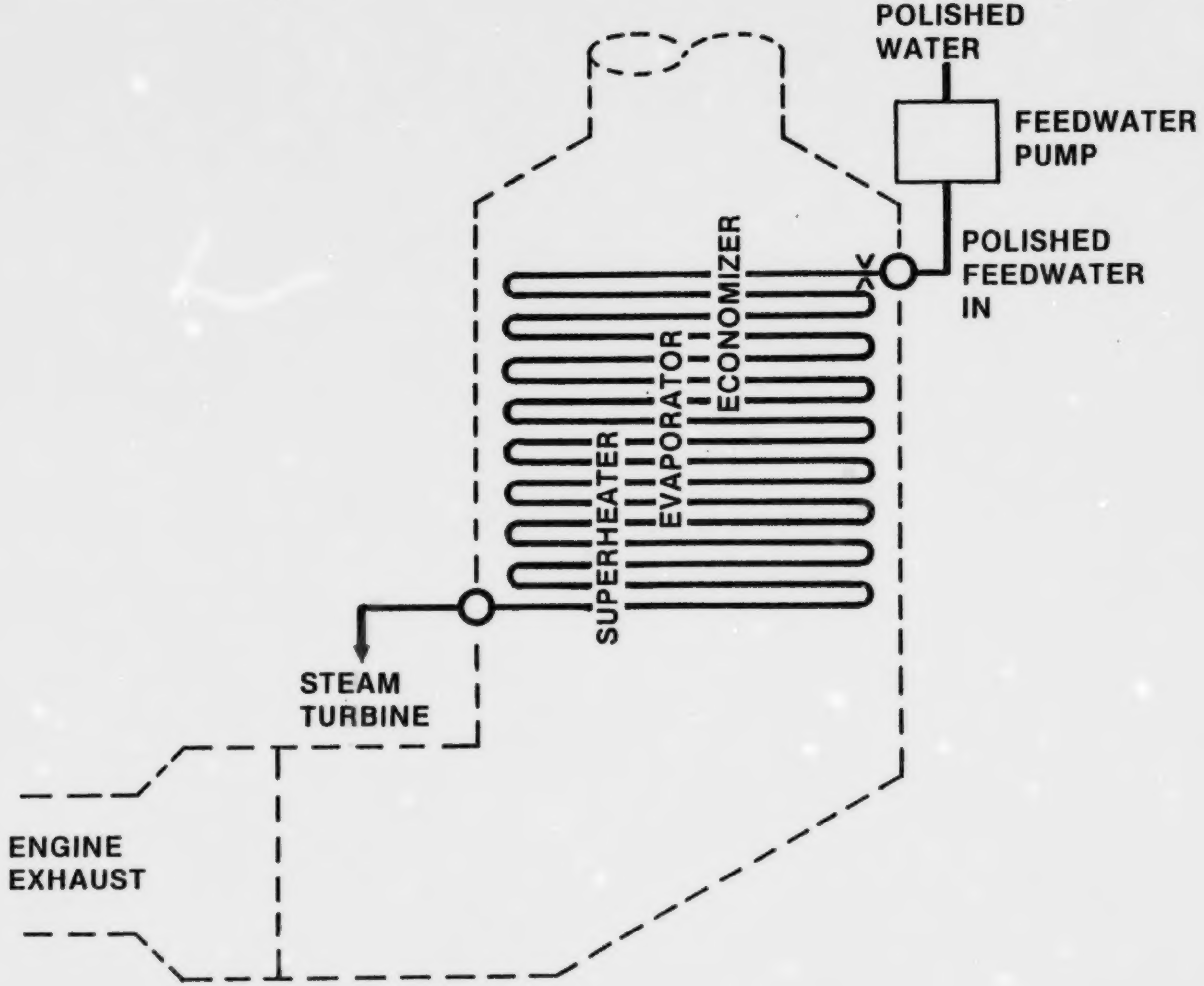
Mars Combined Cycle Schematic


HRSG
WATER
CONTROL
VALVE
COMB.
RED.
GEAR
STEAM
TRIP VALVE
MARS
GAS TURBINE
ELECTRIC
GENERATOR
STEAM TURBINE
DI
CONDENSER
COOLING
TOWER
M
COOLANT
PUMP
M
MAKE-UP
WATER
DEIONIZER
M
BOOST
PUMP
CONDENSATE
POLISHER
M
FEED
PUMP

Conventional Heat Recovery Boiler

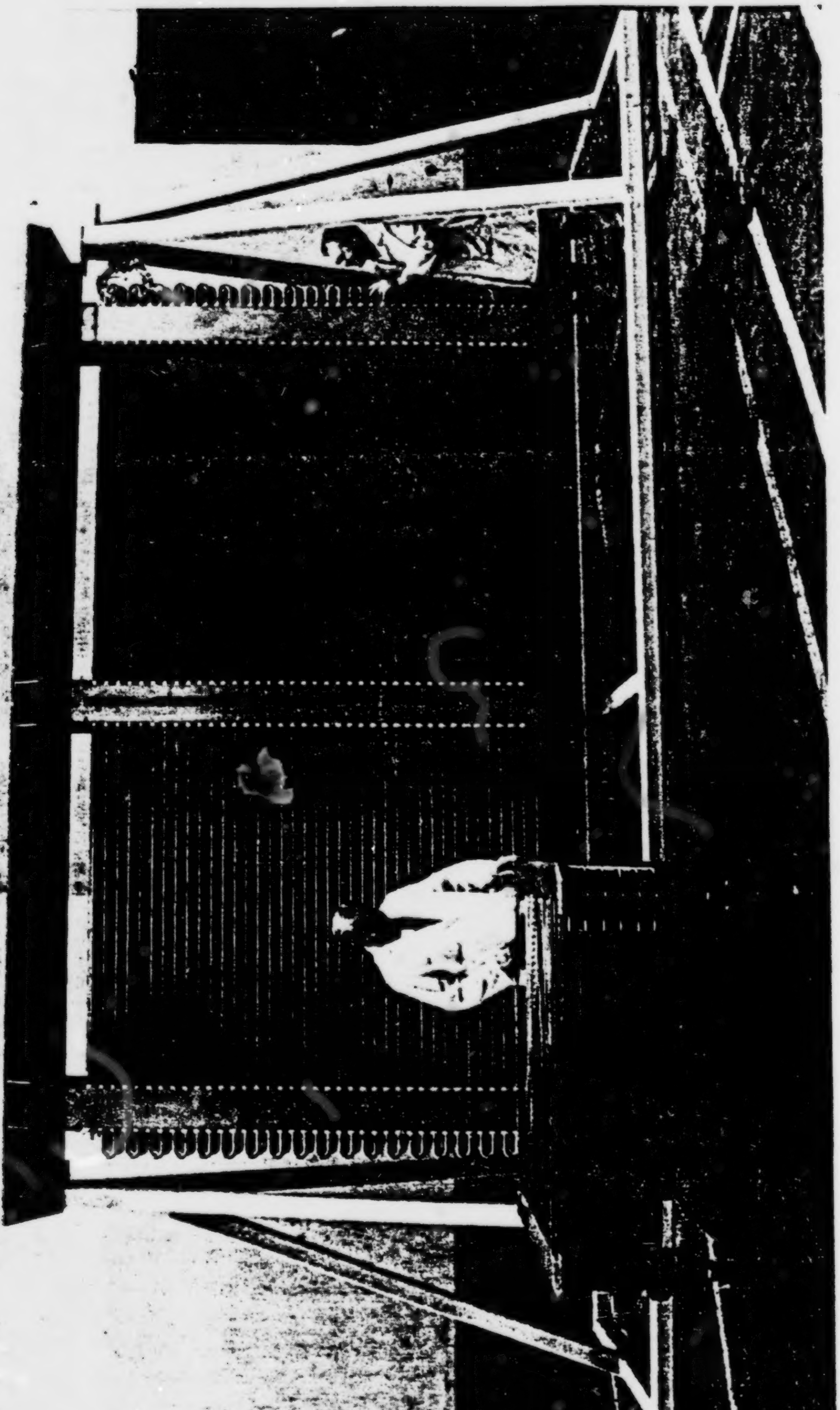

BYPASS STACK
TO TURBINE
DAMPER VALVE(S)
DUCT BURNER
SURFACE BLOW
BOTTOM BLOW DOWN
STEAM DRUM
LEVEL CONTROL
CHEMICAL INJECTION
DEAERATING FEED HEATER
FEEDWATER PUMP
SUPERHEATER
EVAPORATOR
ECONOMIZER

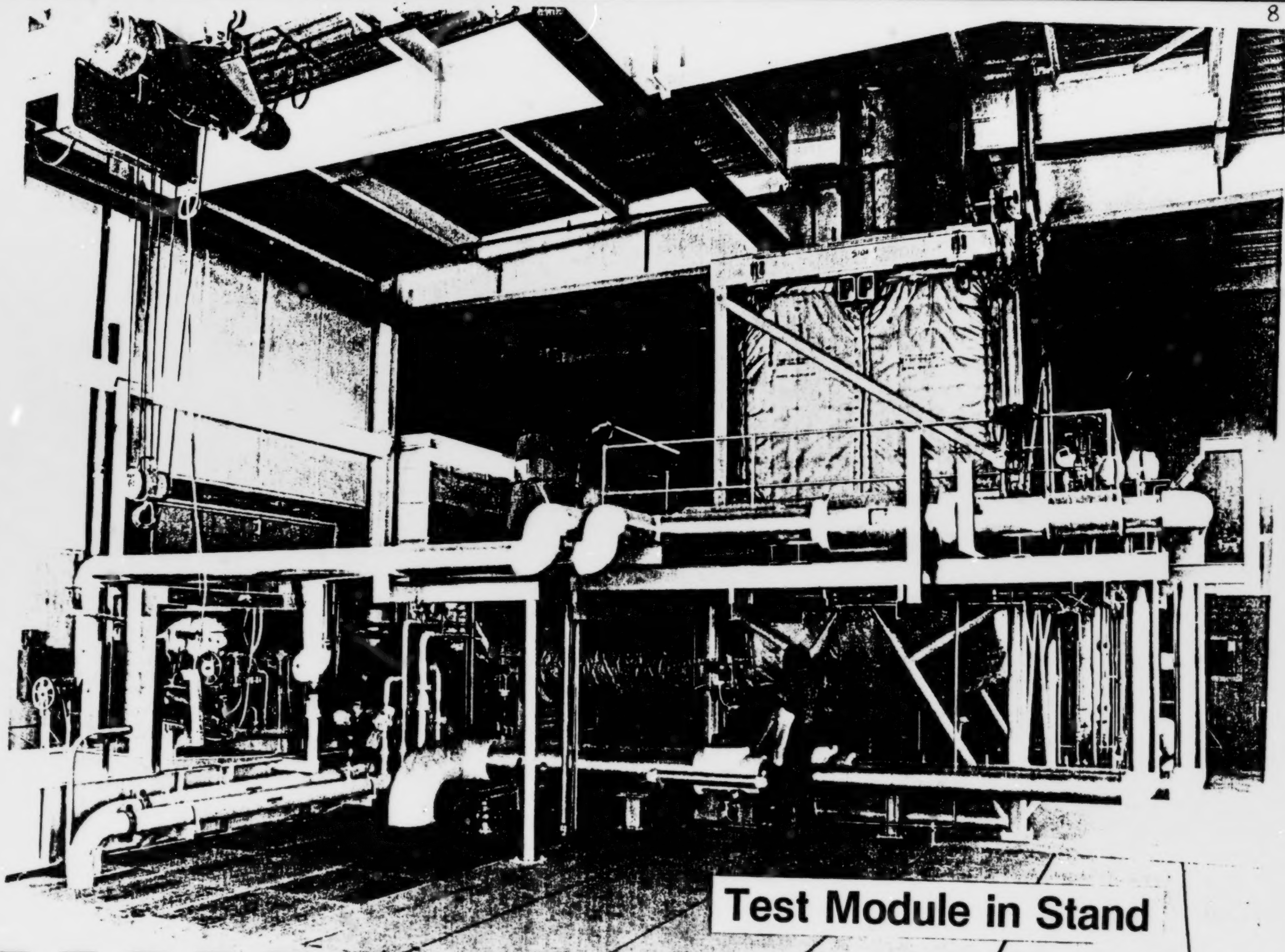
Advanced Once - Through HRSG


POLISHED WATER
FEEDWATER PUMP
POLISHED FEEDWATER IN
ECONOMIZER
EVAPORATOR
SUPERHEATER
STEAM TURBINE
ENGINE EXHAUST

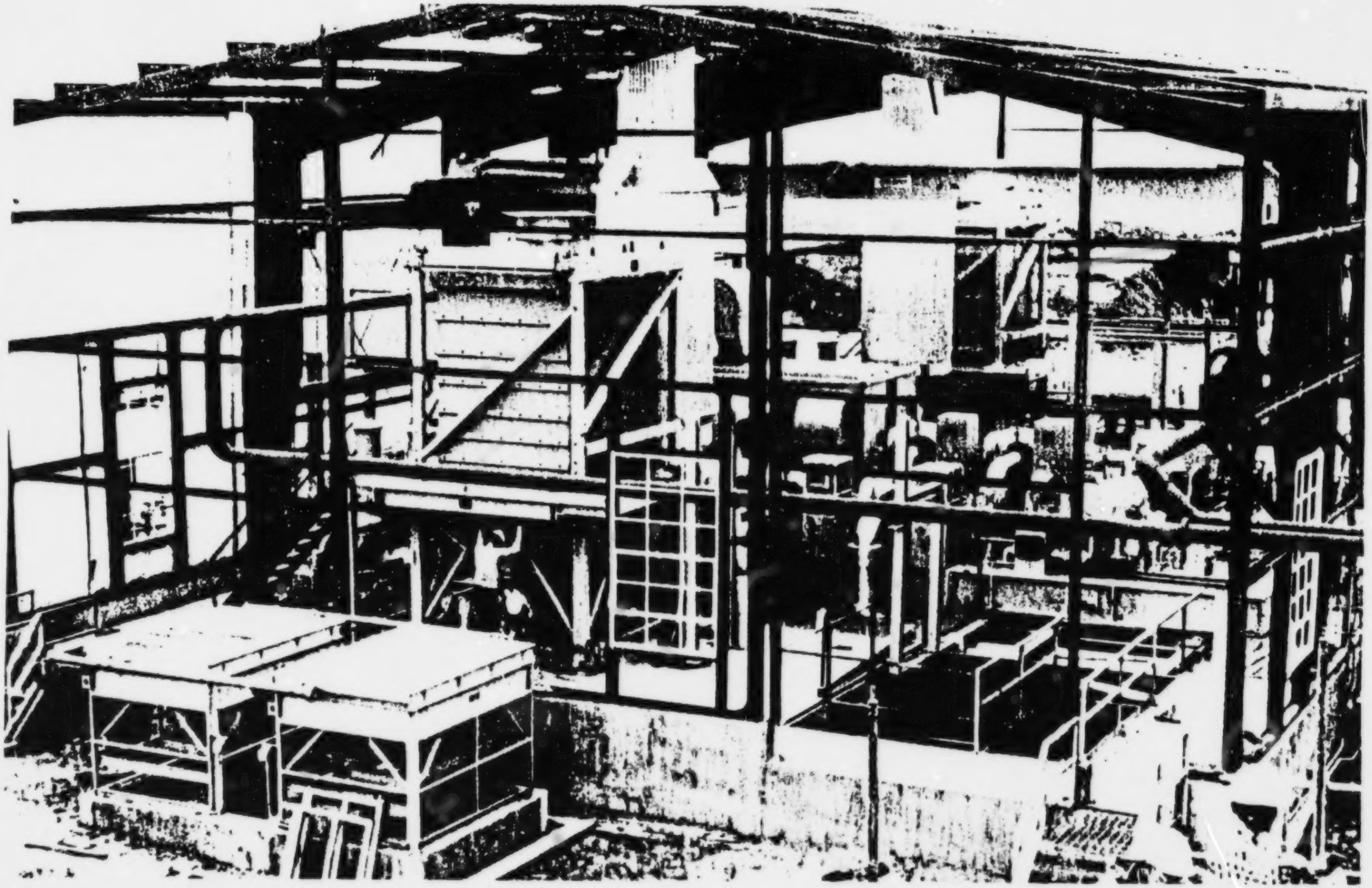
Benefits of Once-Through Steam Generator

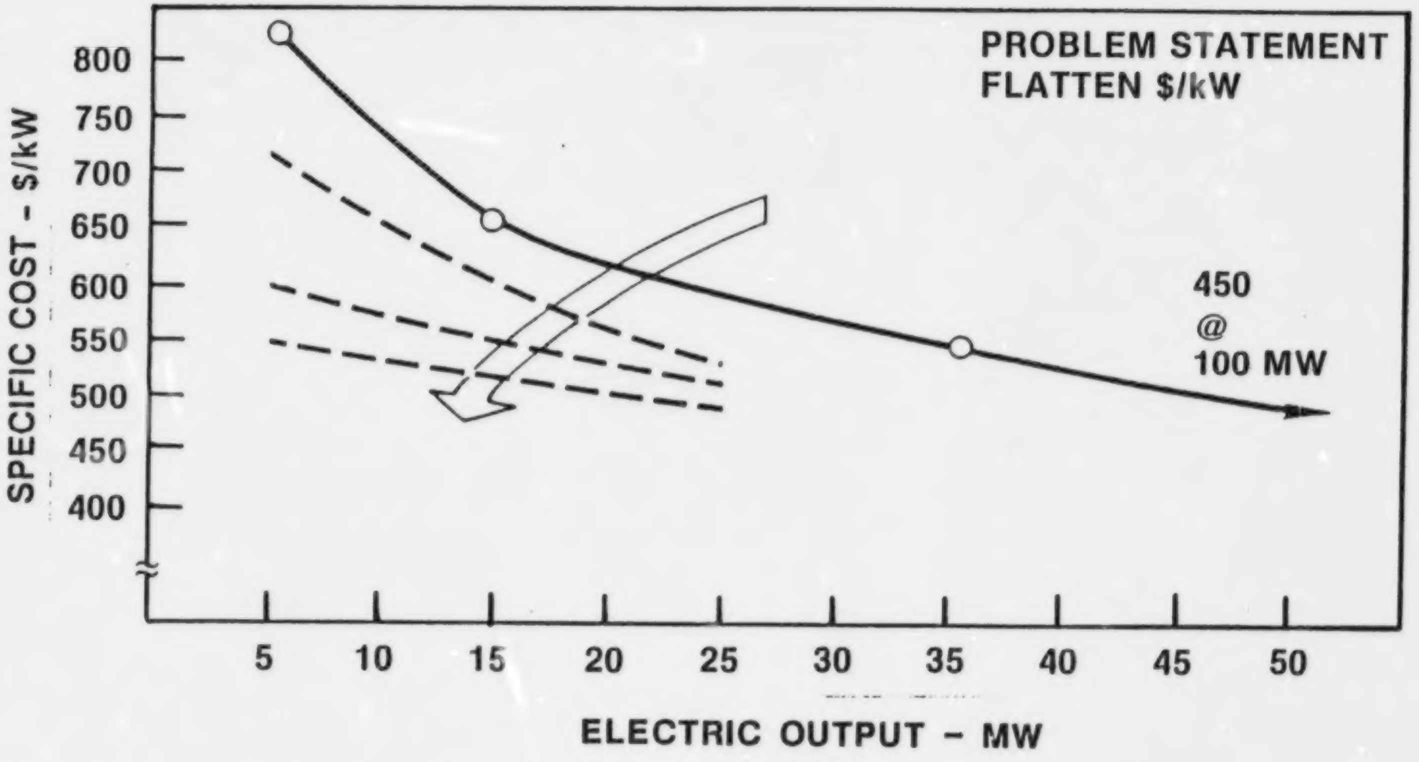
- Simplicity — No Drums, Level Controls, Blowdown, etc
- Large Turn Down Range (Flexible Geometry)
- Long Life and Reduced Maintenance
- Passive Water Treatment — No Chemical Addition
- Inherently Safe — Low Energy Storage, Small Tubes
- Factory Assembled, Compact Package





Test Module in Stand




PROBLEM STATEMENT
FLATTEN $/kW
450
@
100 MW
SPECIFIC COST - $/kW
800
750
700
650
600
550
500
450
400
5
10
15
20
25
30
35
40
45
50
ELECTRIC OUTPUT - MW

Cogeneration Improvement Objectives

Improve Economics to Stimulate Implementation

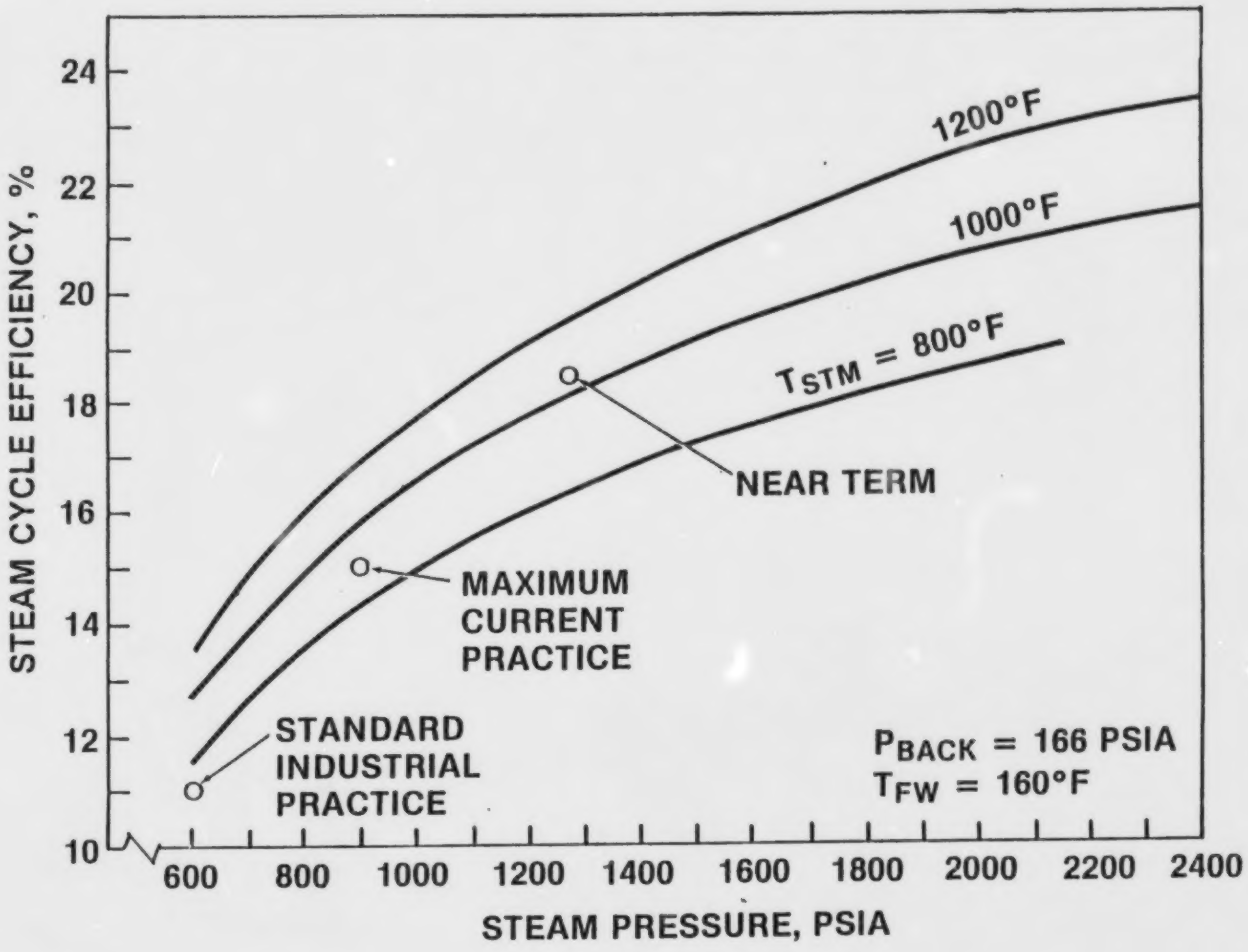
(Provide High Return on Investment)

- Reduce Installed Cost ($/kW) or ($/pph)
- Increase Operating Efficiency
  - Overall Fuel Utilization Efficiency
  - Part Load Performance
  - Flexibility (Electrical and Thermal Variation)
- Provide High Reliability/Availability
- Reduce Operating and Maintenance Costs

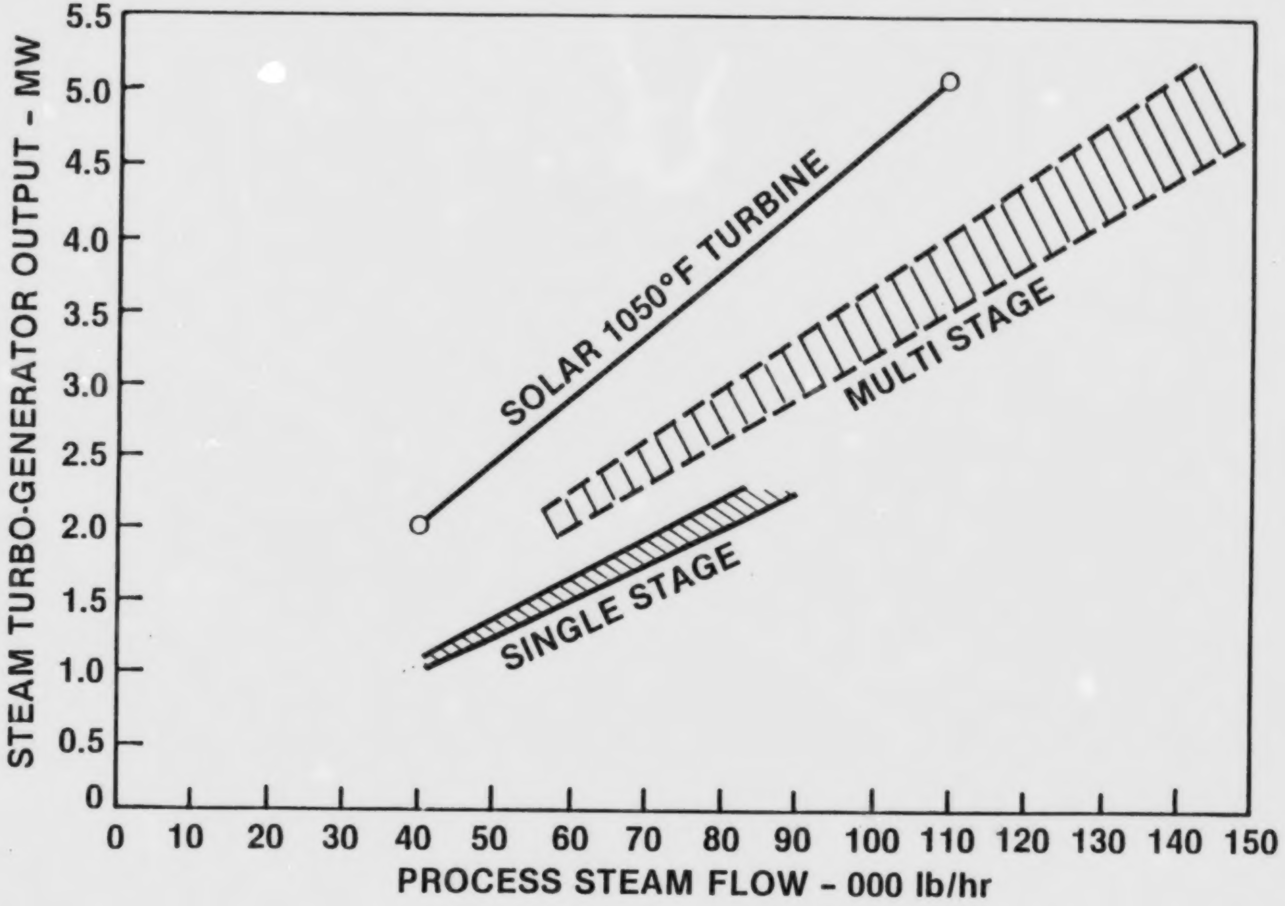
“New” Steam Approach

- Simple Once-Through Steam Generator
- Corrosion Resistant Materials
- Passive Water Treatment
- High Efficiency Cycles
- New Steam Turbines
- Integrated System of Matched Components
- Factory Assembled and Tested
- Fully Automated Control Systems

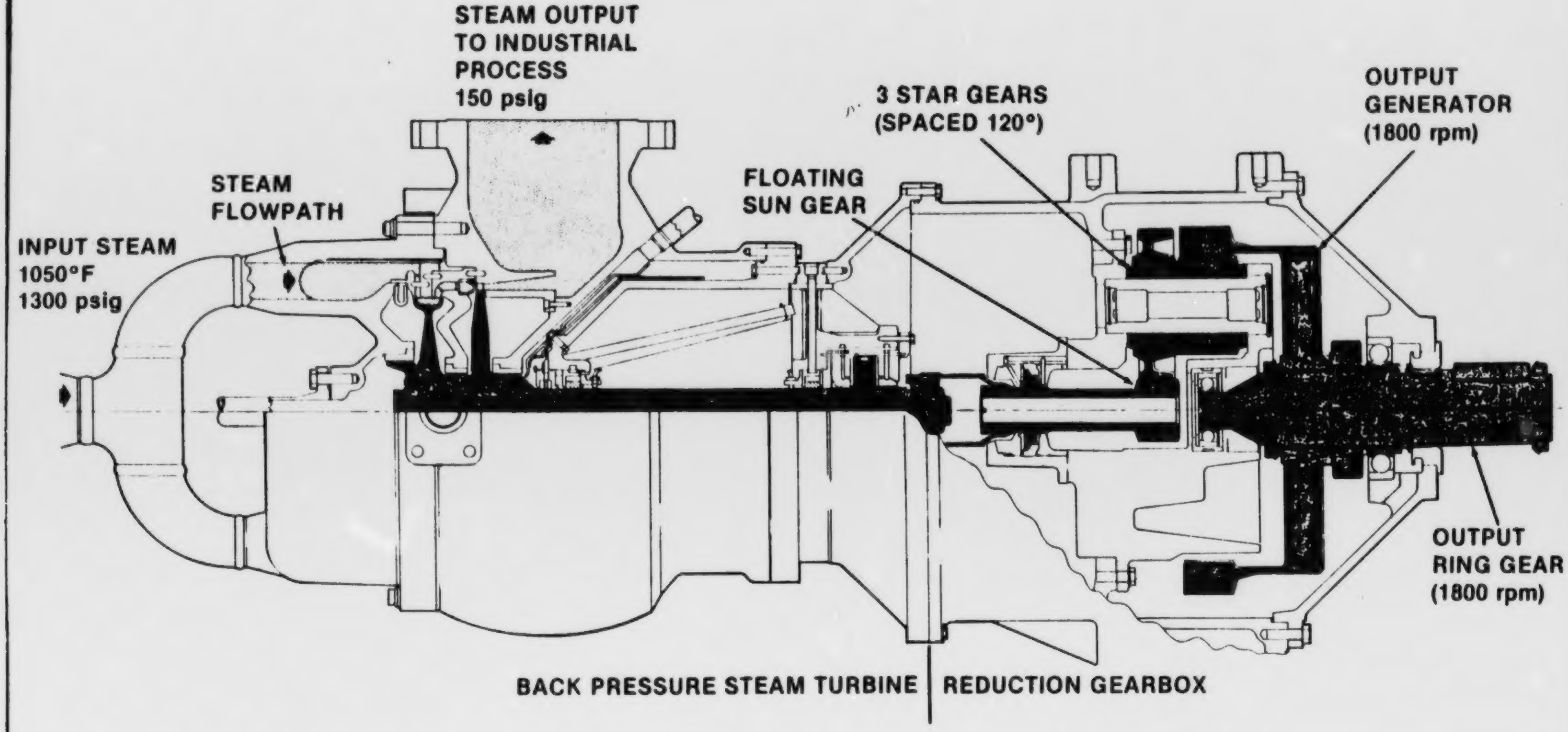
Ideal Steam Cycle Efficiency for Back Pressure Turbines



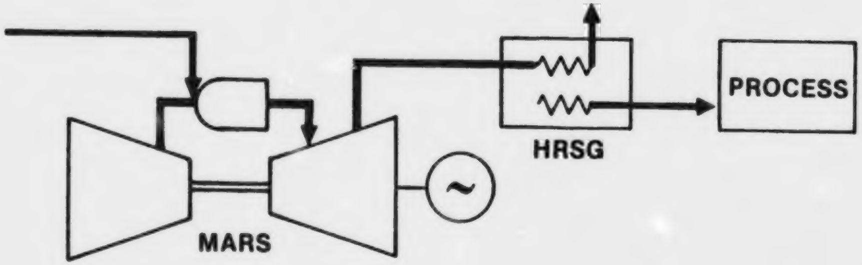
Electrical Output from Steam Turbo-Generators

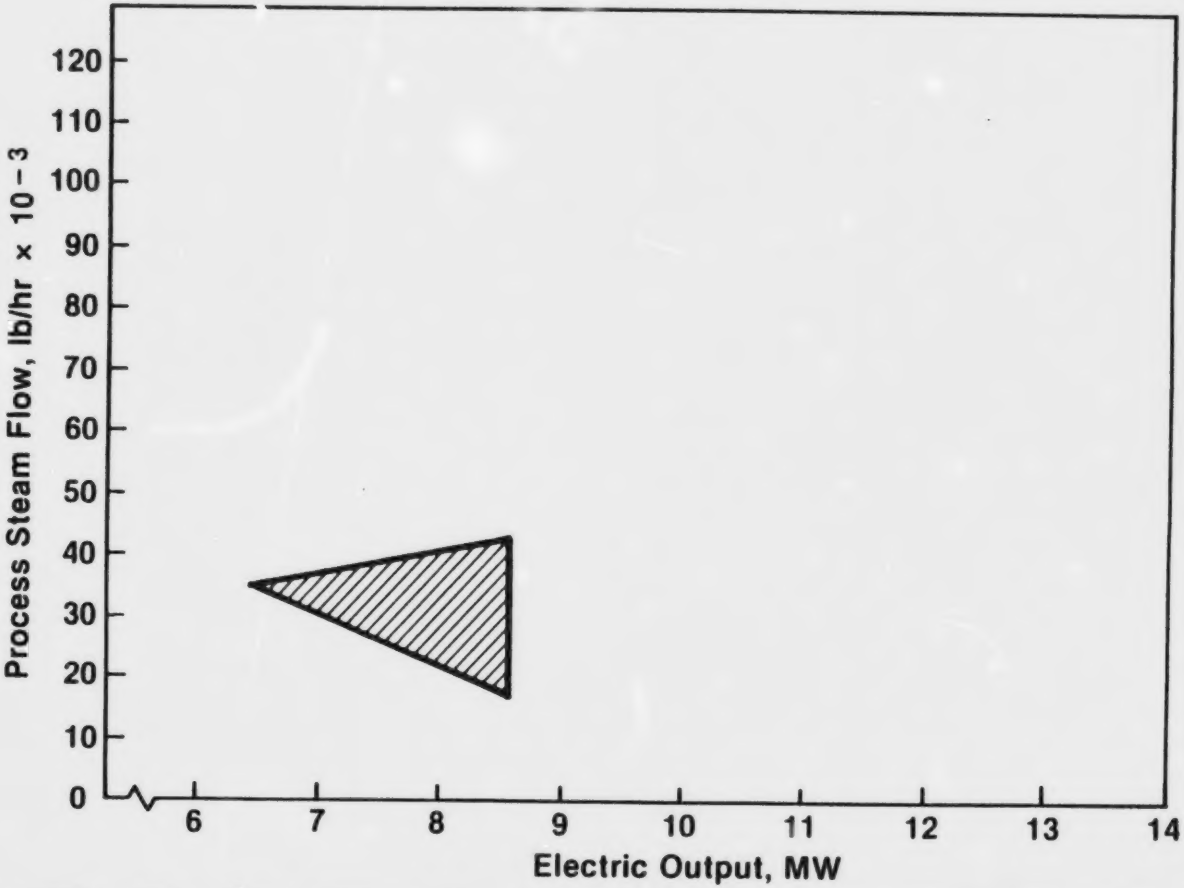


NOTES: • INCLUDES EFFECT OF STEAM TEMP & PRESS
• 150 PSIG BACK PRESSURE

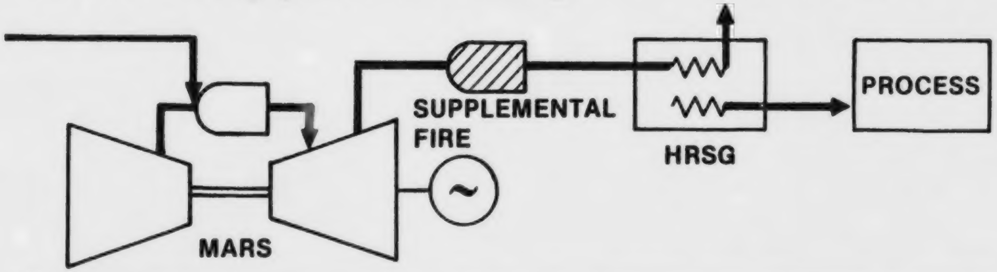

STEAM OUTPUT TO INDUSTRIAL PROCESS 150 psig
STEAM FLOWPATH
INPUT STEAM 1050°F 1300 psig
FLOATING SUN GEAR
3 STAR GEARS (SPACED 120°)
OUTPUT GENERATOR (1800 rpm)
OUTPUT RING GEAR (1800 rpm)
BACK PRESSURE STEAM TURBINE
REDUCTION GEARBOX

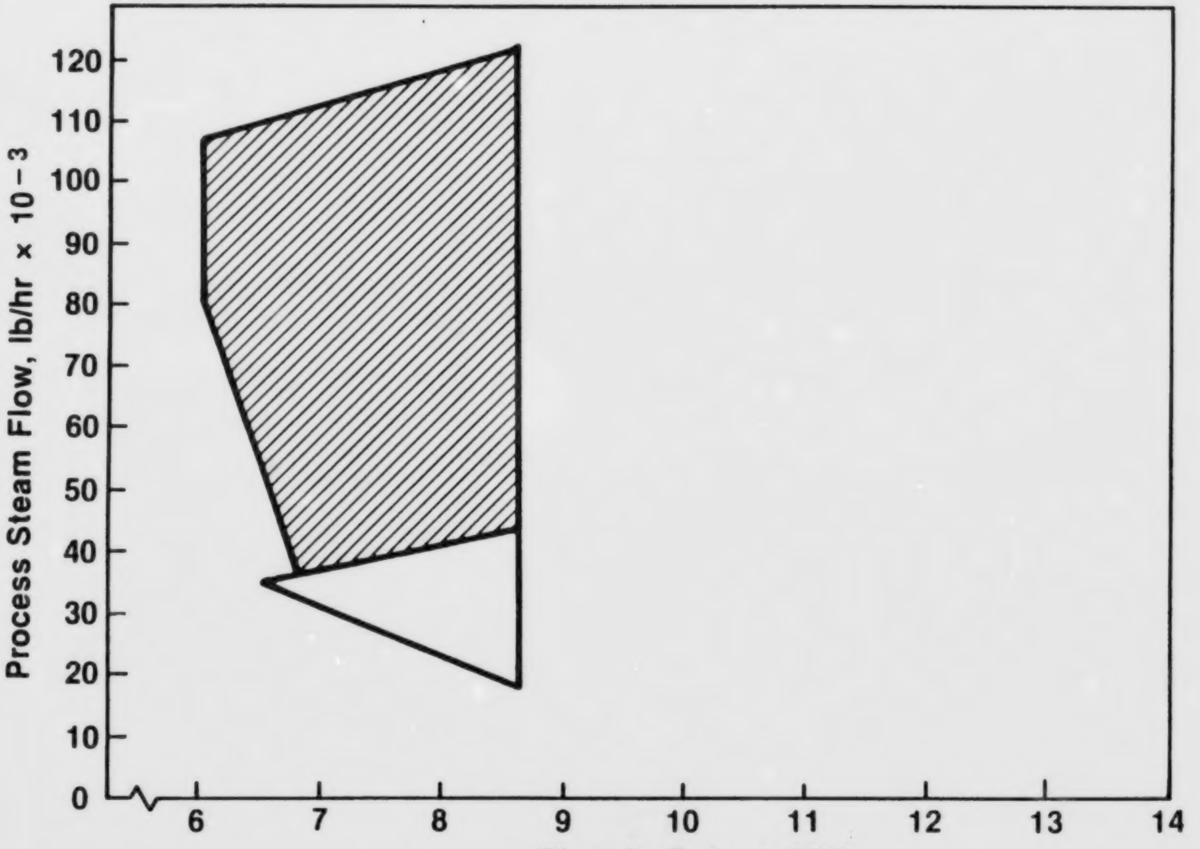
Mars Simple Cycle with Unfired HRSG


HRSG
PROCESS
MARS
~



Mars Simple Cycle with Supplementary Fired HRSG

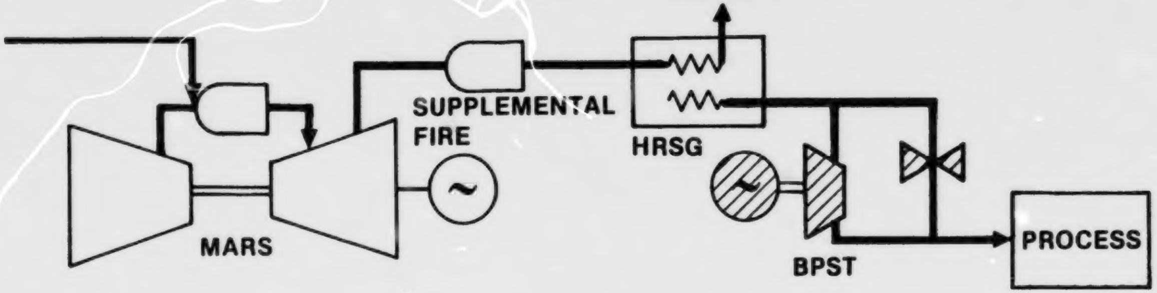

SUPPLEMENTAL
FIRE
HRSG
PROCESS
MARS

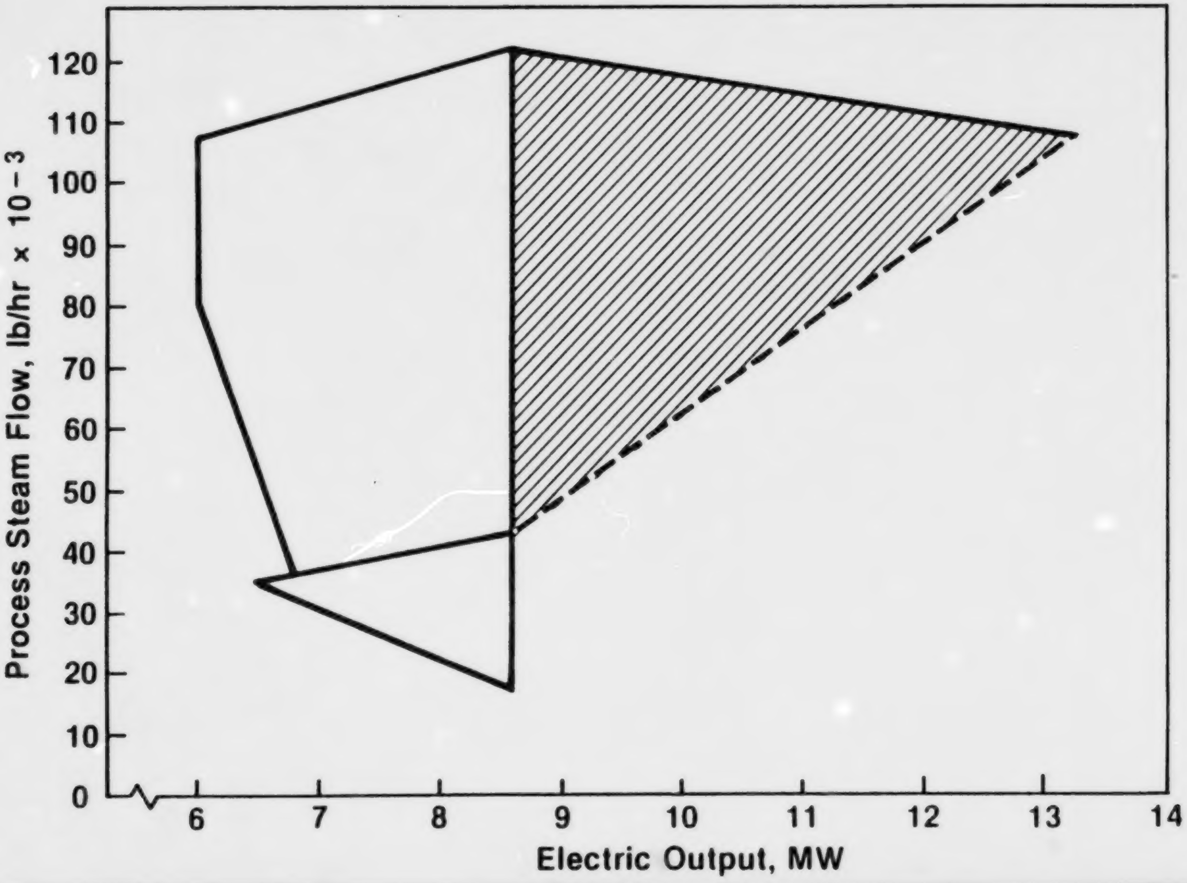


Benefits of Supplemental Firing

- Increases Steam Production
- Increases Overall Fuel Utilization Efficiency
- Provides Effective Method for Thermal Modulation
- Reduces Specific Cost of Thermal Production ($/pph)
- Increases Return on Investment

Mars Combined Cycle with Back Pressure Steam Turbine

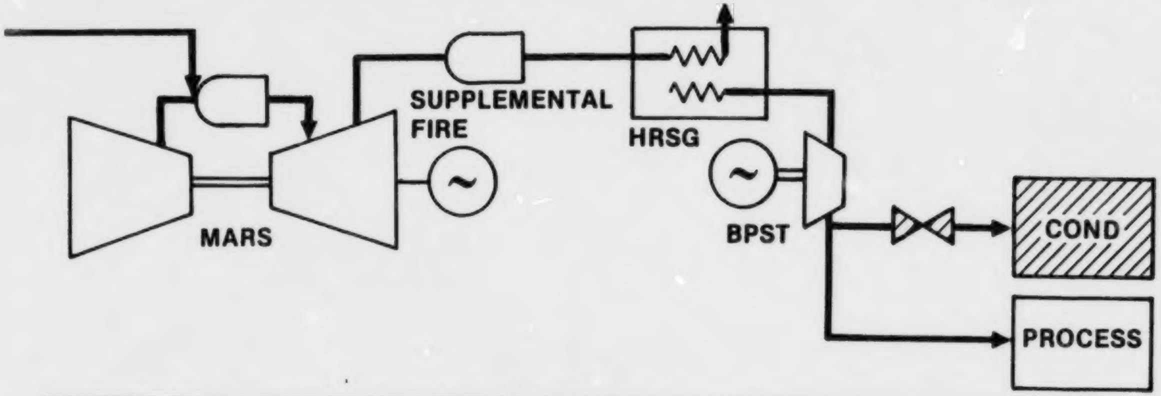

SUPPLEMENTAL FIRE
HRSG
MARS
BPST
PROCESS

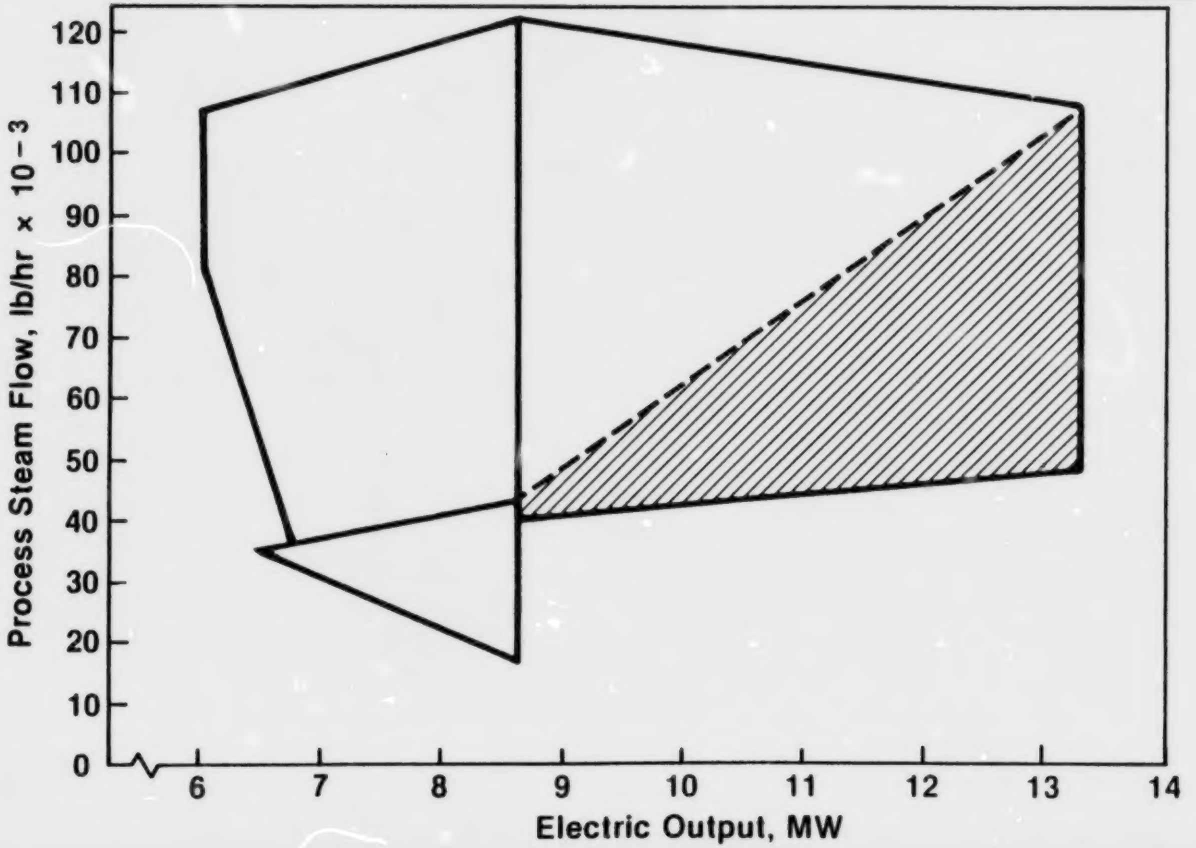


Benefits of Back Pressure Steam Turbine

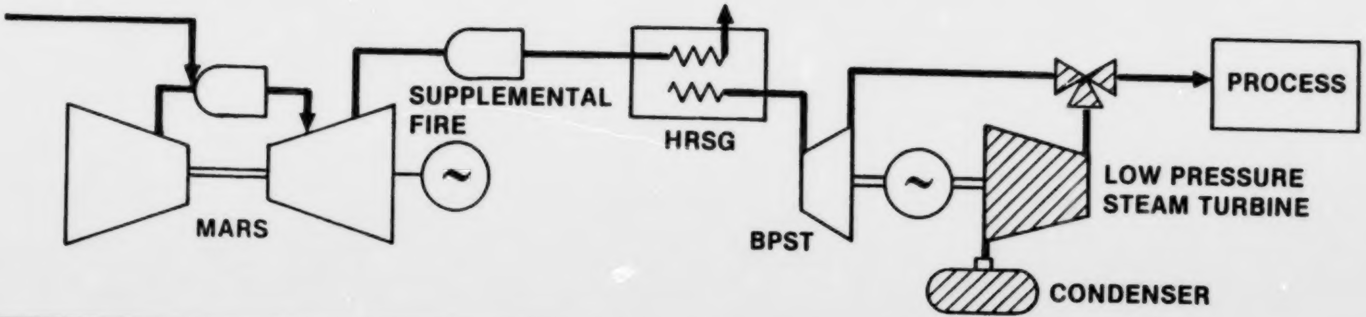
- Additional Electricity at Very Low Incremental Heat Rate
- Reduces Specific Cost ($/kW)
- Increases Flexibility — Variable Electrical/Thermal Ratio
- Increases Return on Investment

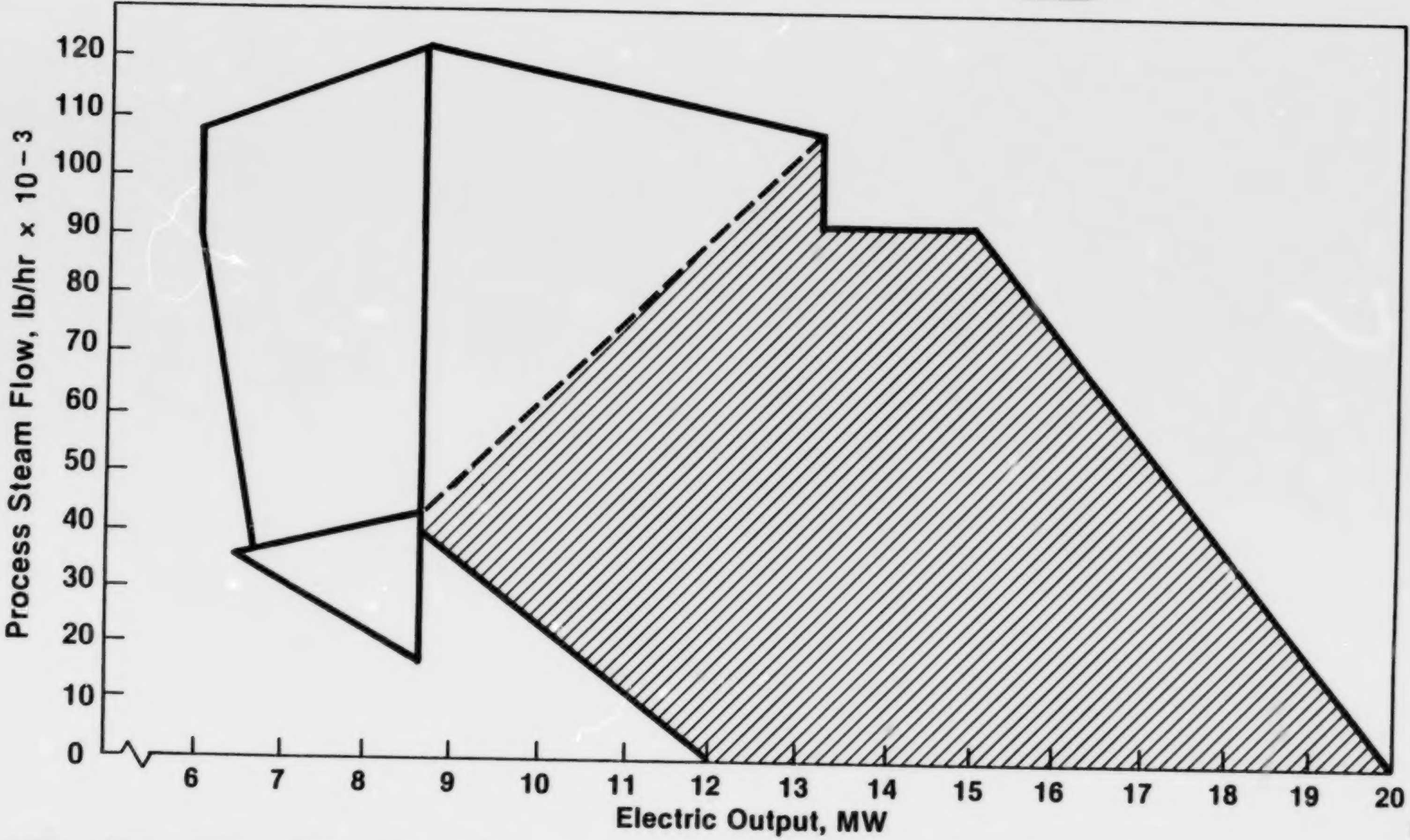
Mars Combined Cycle with BPST and Process Bypass


SUPPLEMENTAL FIRE
HRSG
MARS
BPST
COND
PROCESS



Mars Combined Cycle with Extraction Turbine


SUPPLEMENTAL FIRE
HRSG
PROCESS
MARS
BPST
LOW PRESSURE STEAM TURBINE
CONDENSER

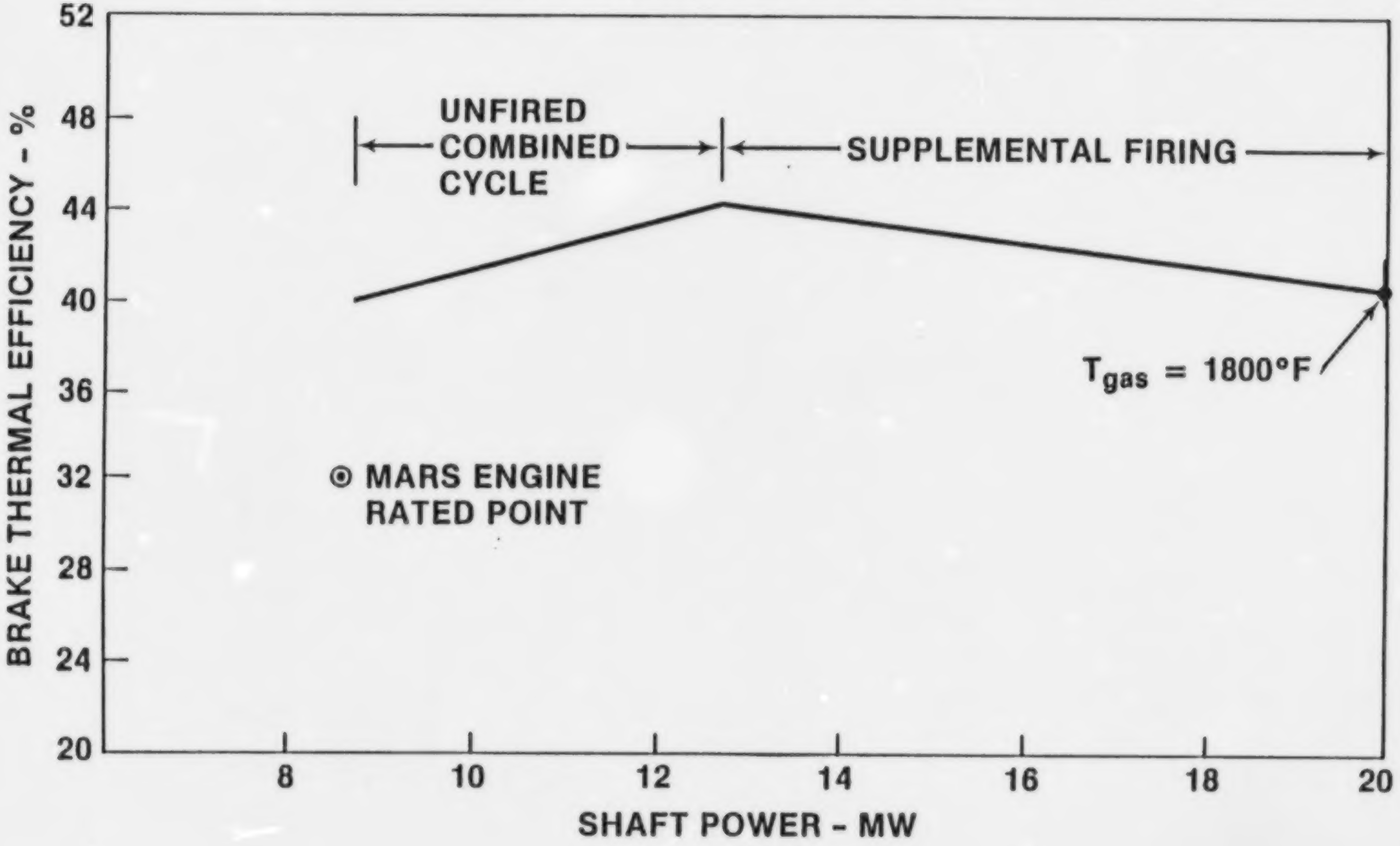


Benefits of Extraction (or Condensing) Steam Turbine

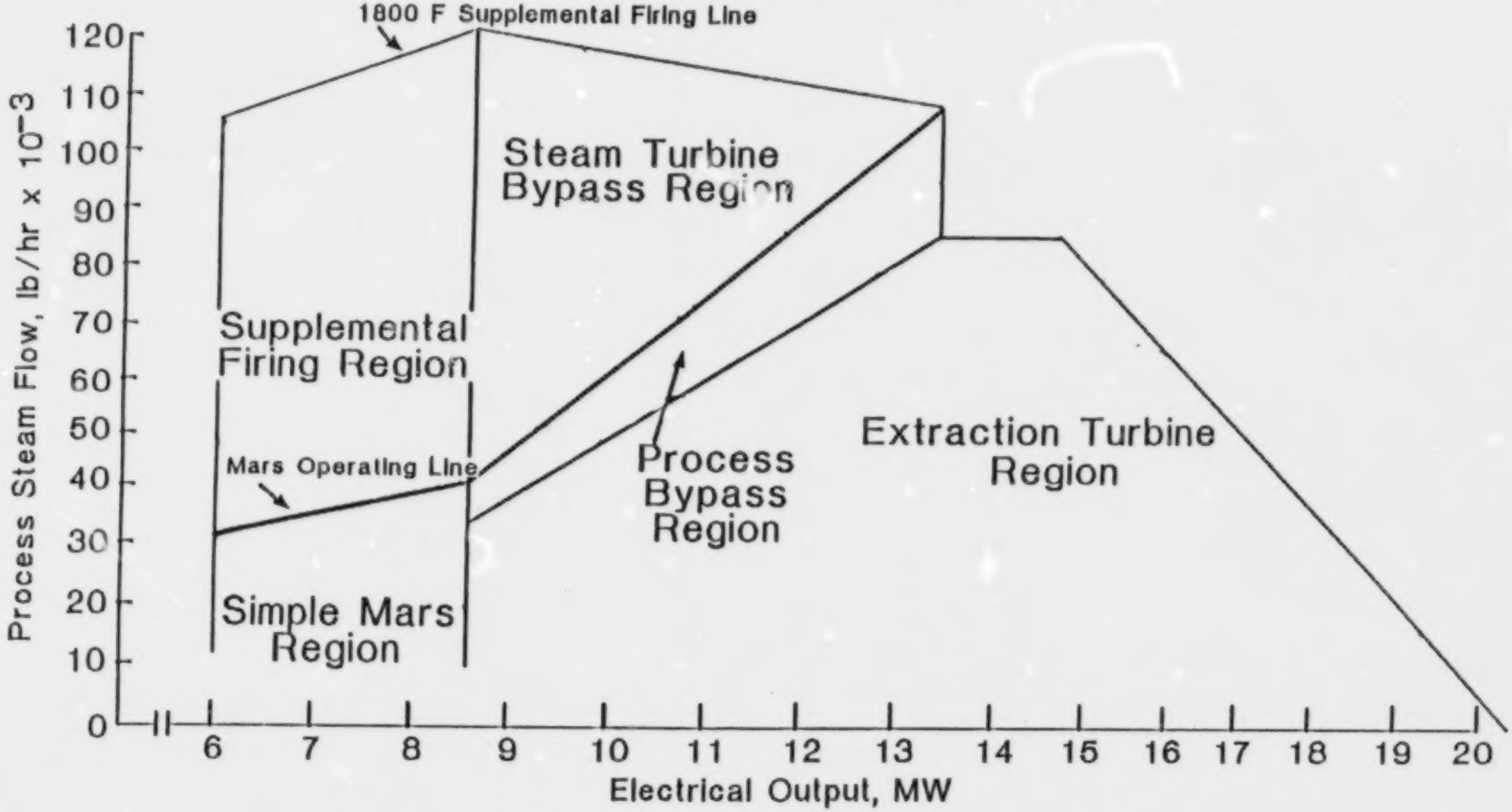
- Provides Maximum Flexibility Between Electrical and Thermal Output
- Reduces Installed Cost per Peak Kilowatt
- Maximizes Electrical Output and Electrical Efficiency

Mars Combined Cycle with Back Pressure and Condensing Steam Turbines

High Efficiency Over Broad Power Range



Mars Cogeneration Systems



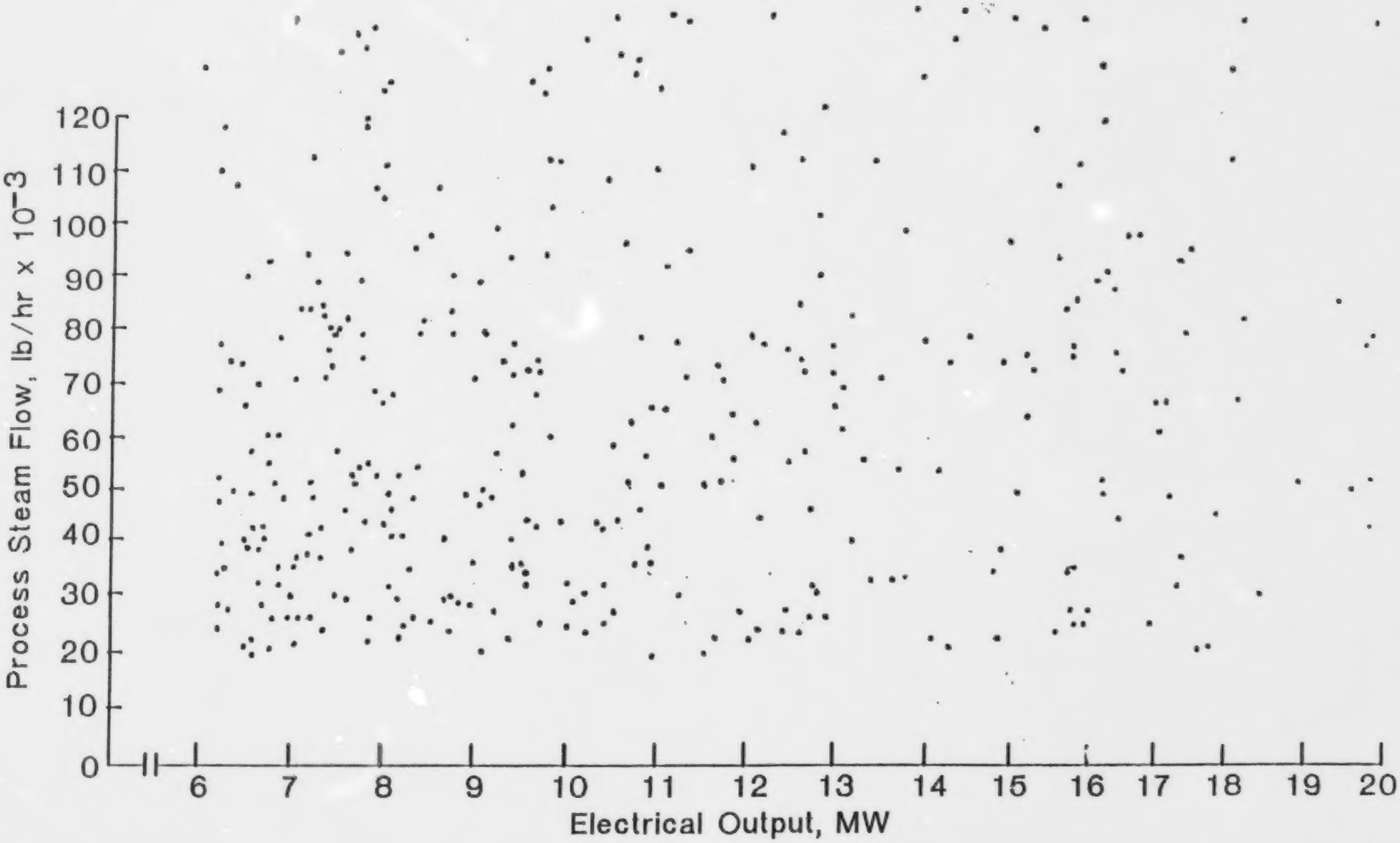
Industrial Cogeneration Survey

Dun & Bradstreet Industrial Data Base

- 21,000 Industrial Plants
  - 90% of Total Industrial Energy Consumption
- Requirements for Cogeneration Potential
  - Annual Operating Hours > 6,000
  - Price of Electricity > $.05/KWh
  - 4,700 Plants Meet These 2 Criteria
- Requirements for this Study
  - Steam Demand > 15,000 lb/hr
  - Electric Demand > 4 MW
  - 1,000 Plants Surveyed

Existing Industrial Sites

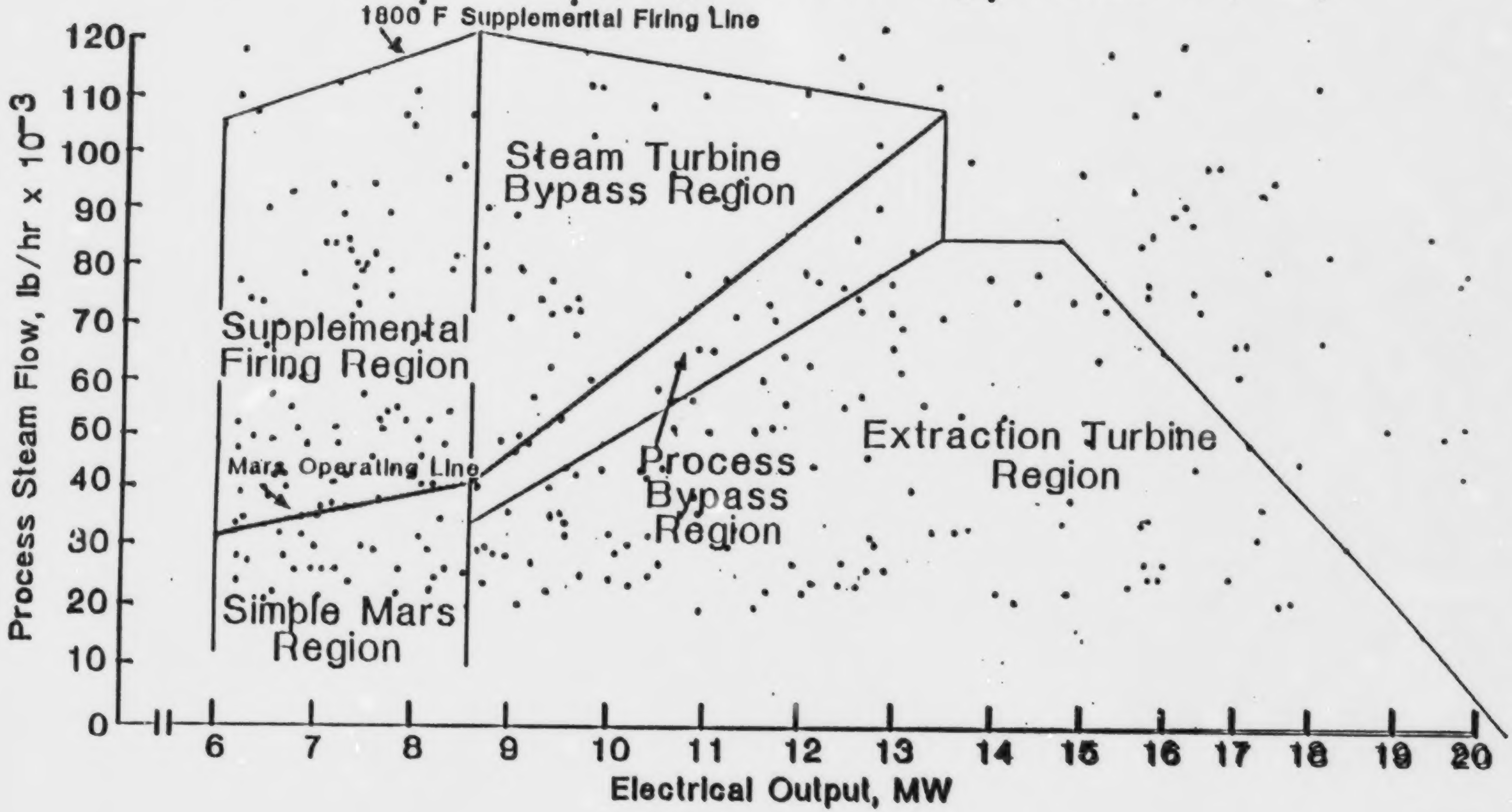
Energy Needs



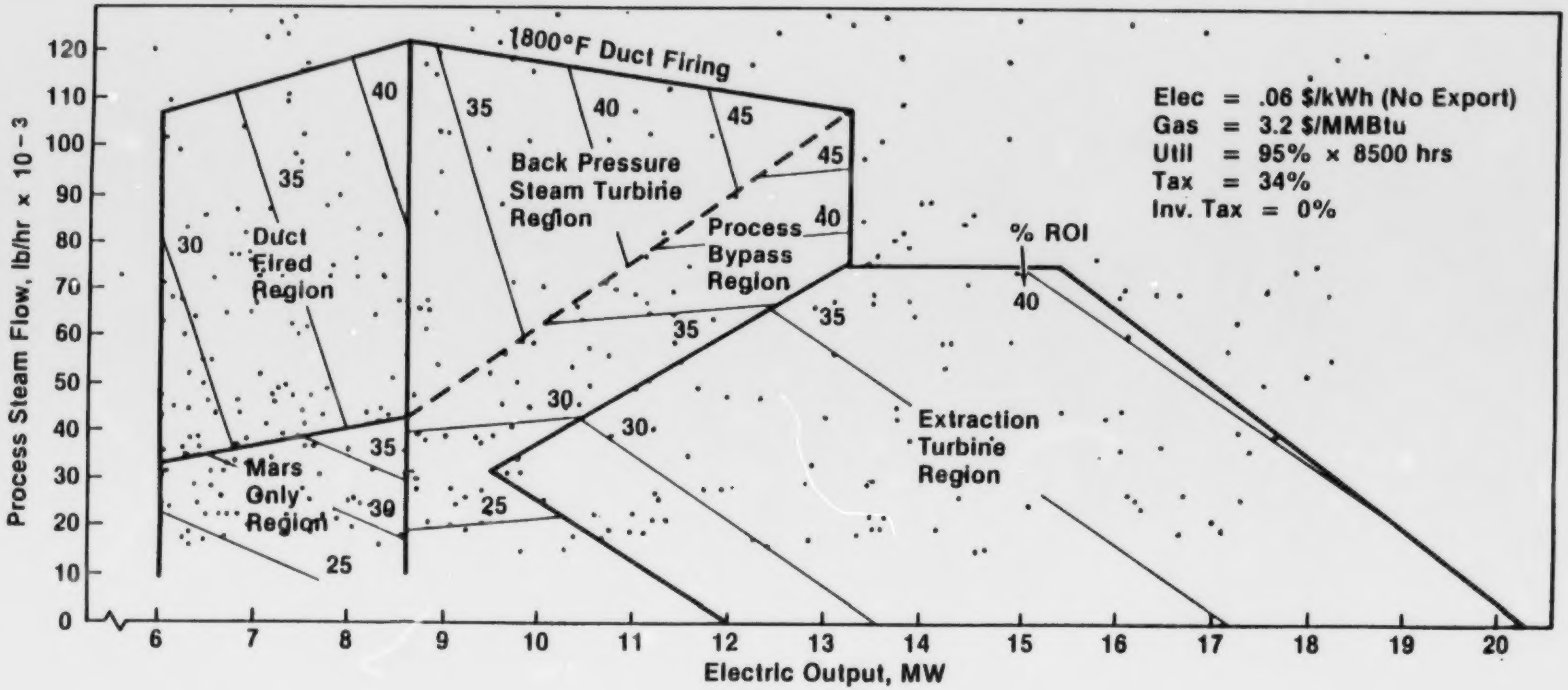
Existing Industrial Sites

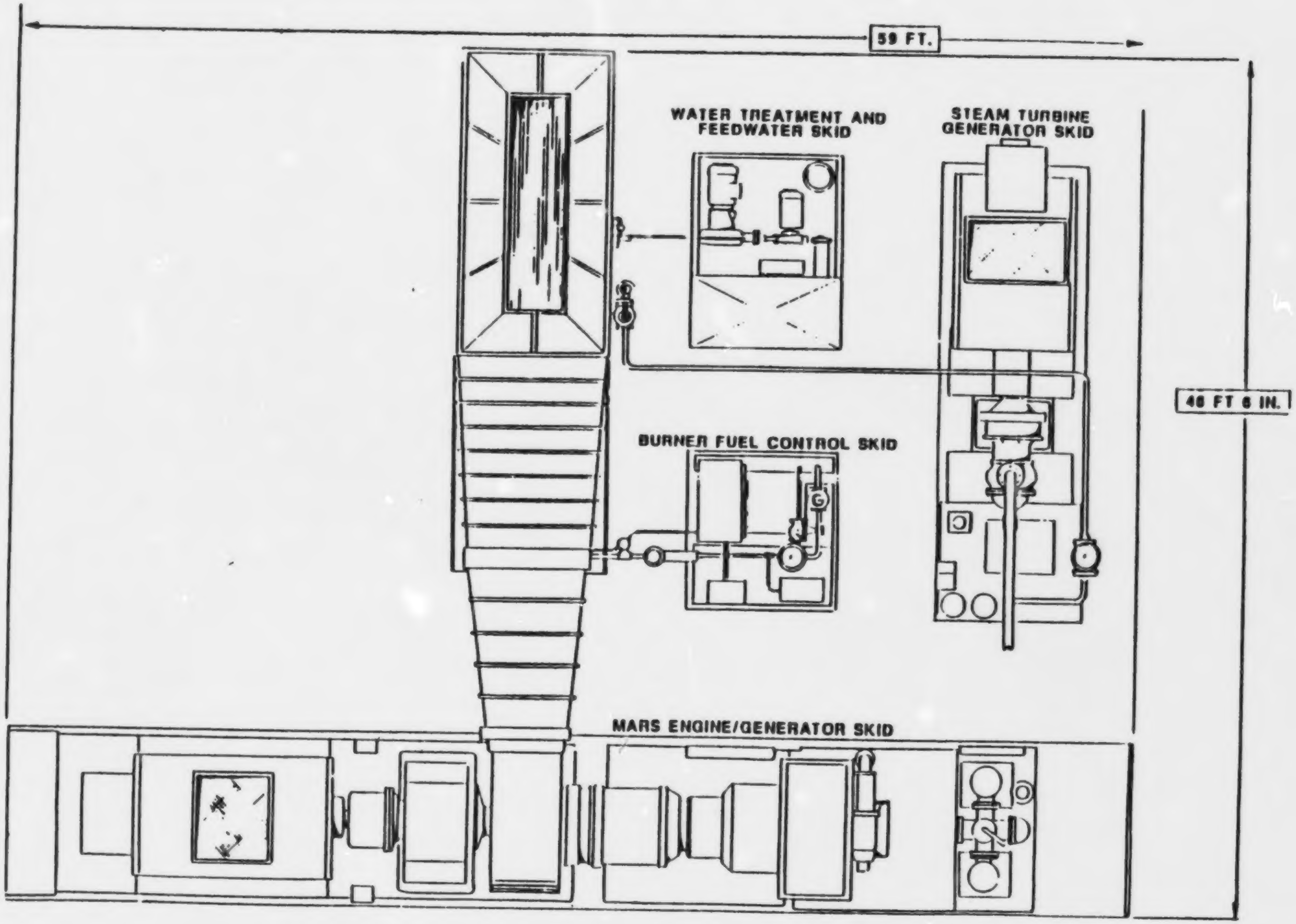
Energy Needs

Mars Cogeneration Systems



Mars Cogeneration Systems — Return on Investment Map




59 FT.
WATER TREATMENT AND FEEDWATER SKID
STEAM TURBINE GENERATOR SKID
46 FT 6 IN.
BURNER FUEL CONTROL SKID
G
MARS ENGINE/GENERATOR SKID

Installation Arrangement of Cogeneration System With Back Pressure Steam Turbine

Cheng Cyle
Concepts and Applications in Small Gas Turbines

By
J. DeVaal and B. Ashford
Cullen Detroit Diesel Allison Ltd.

6

Cheng Cycle - Concepts and Applications in Small Gas Turbines

J. DeVaal and B. Ashford, Cullen Detroit Diesel Allison Ltd.

There have been several exciting developments in gas turbine design and performance in recent years. These have included higher turbine inlet temperatures through improved blade cooling (up to 1250°C or nearly 2300°F), even greater fuel flexibility (low BTU gas, solid fuels and indirect firing), reduced emissions and increased power output (through water and steam injection), and several others.

One of the more interesting developments of late has been of particular significance to the cogeneration industry. Although steam injection for power augmentation on gas turbine engines is not a new concept, it is only in the last few years that it has been fully developed into a viable operating option. There can be little doubt that this development has been spearheaded in large part by the Cheng Cycle concept, and its application in the IPT Series 7 cogeneration system. Many of you may already be familiar with this system, but a brief recap is probably in order.

IPT (International Power Technology) was founded in 1974 by Dr. Dah Yu Cheng. During the 1970's Dr. Cheng and his research staff developed and patented the Cheng Cycle concept and tested it on a variety of gas turbines. Because the Cheng Cycle innovation was a significant departure from traditional gas turbine industry practices, acceptance and commercialization came slowly. By 1982, however, a viable system utilizing an Allison Gas Turbine, model 501 KH, had been developed, and what was to become known as the "Series 7 Cogen System" was launched onto the market. By late 1986, nearly $100 million had been invested in the Cheng Cycle development and its commercial applications. There are currently 6 Series 7 units operating in California, and recent experience has been excellent, after overcoming a variety of early operational problems. There are a further two units currently on order for Loma Linda Hospital in California.

con't on page 2...

The Cheng Cycle dramatically improves the efficiency, flexibility and power output of a cogeneration system with a minimal increase in mechanical complexity.

In the Cheng Cycle, gas turbine exhaust heat is used to produce superheated steam in a heat recovery steam generator. This steam can either be injected into the gas turbine to greatly increase efficiency and power output, or can be used as process thermal energy. The Cheng Cycle combines and optimizes the Brayton (gas turbine) and Rankine (steam turbine) cycles using a single gas turbine as prime mover. Controlled injection of superheated steam into the combustor section provides up to 15% greater mass flow which, because little additional compressor work is required, boosts power by up to 65%. Additionally, because the extra power is produced with only 15% more fuel consumed, electrical efficiency is increased by approximately 40%. Finally, the Cheng Cycle offers intrinsic NO_x suppression because massive steam injection into the combustion flame zone inhibits NO_x formation by effectively cooling high temperature flame areas. A lower temperature, evenly cooled flame zone produces minimal amounts of NO_x. Test results indicate between 10 and 30 parts per million of NO_x, depending upon the level of steam injection compared to 80-120 parts per million without steam injection.

A typical arrangement of the Series 7 system is shown in Fig. 1, and the basic performance parameters are shown in Fig 2. As can be seen, the electrical output of the turbine (which is nominally 3.5 MW without steam injection) is increased to around 5.4 MW with full injection. With very little modification to the Allison 501 gas turbine engine itself, this represents a rather phenomenal increase in power. (Needless to say, not all engines are inherently capable of this type of power boost, but several other manufacturers are now reviewing and upgrading their capabilities). The really significant feature of this patented steam injection operating cycle, however,

con't on page 3...

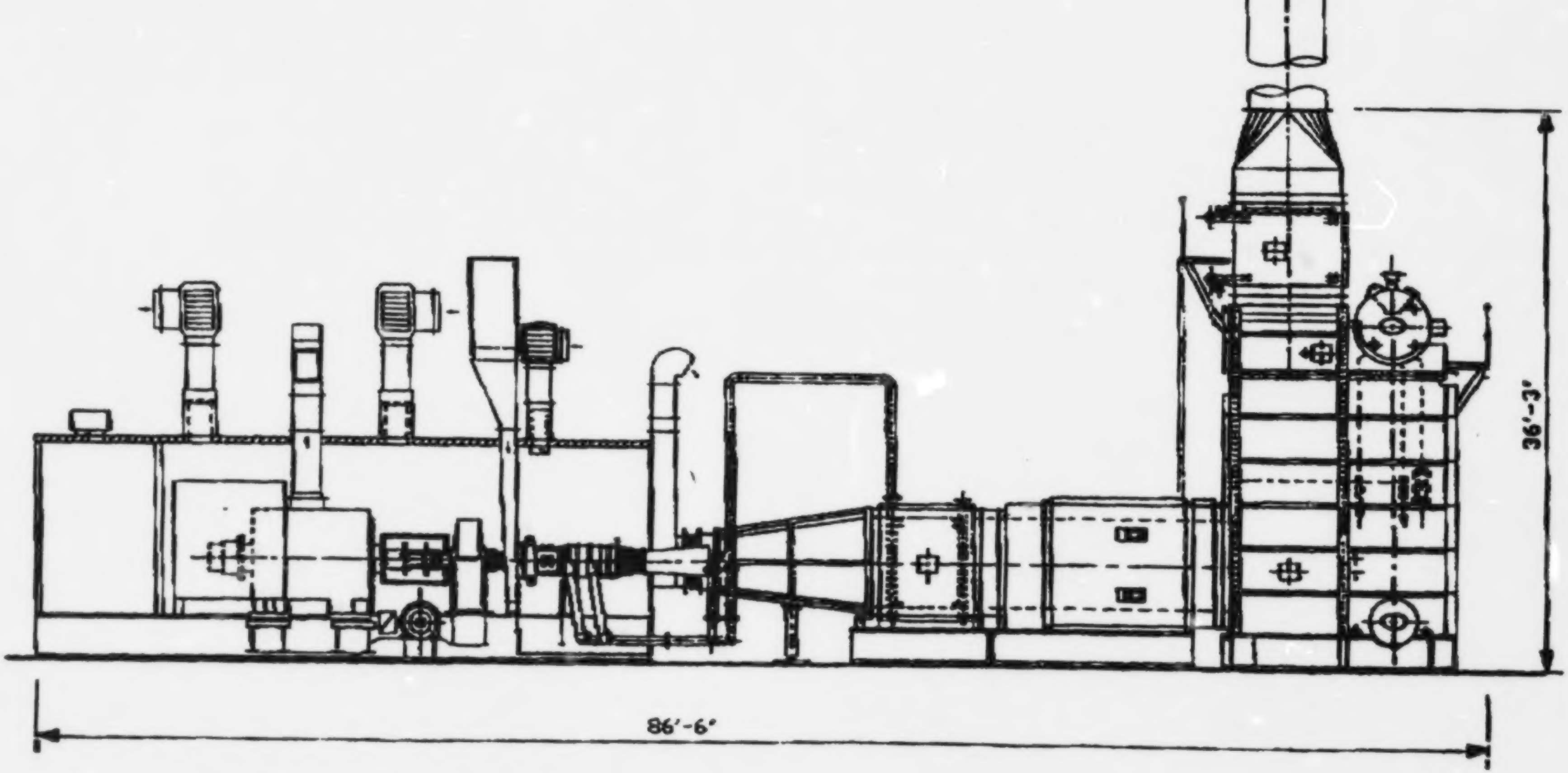
lies in its optimization of the electrical and thermal outputs for any given set of circumstances. To this end, IPT have developed a comprehensive computer program, utilizing a Bailey network 90 system. This program allows the system to track various parameters (such as ambient temperature, steam demand, KW demand, fuel cost, KW revenue etc) and select the most economical operating point. This program will even take into account any changes in gas cost or KW revenue rates during the course of the day, and adjust the optimum point automatically. (In reality, of course, if an installation is connected to a utility, the economics often dictate that the maximum possible electrical output be produced continuously).

Having developed the 5.4 MW Series 7 into a reliable system, IPT embarked on developing a smaller system in the 1.5 - 2 MW range, which they identified as filling a need in the small power user range. About two years ago they reached an agreement with Kawasaki to jointly develope a "Series 5" model, based on the Kawasaki M1A-01 industrial gas turbine which is nominally rated around 1.1 MW at ISO conditions. The operating regime initially envisaged for this unit is shown in Figure 3. As can be seen, the output power with full injection is increased to around 1860 KW,and up to 19000 lbs/hr of process steam is available. At the end of 1986, IPT decided that due to other commitments they could no longer participate in this program, and since then Kawasaki have continued development on their own. The first of these units is currently undergoing trials in Japan, but so as to have time to eliminate the kind of problems that plagued the early Series 7 units, they are only anticipating commercialization during 1989/1990. On the M1A, as on the Series 7, the higher rating has necessitated a larger gearbox which is part of Kawasaki's supply.

con't on page 4...

There are also of course, extensive modifications to the combustor design itself, but the basic turbine blading, shafting, etc. is essentially unchanged. An initial conceptual layout for the generator set is shown inFig. 4, and a total plant layout option is shown in Fig 5. This represents acompact, functional arrangement, including auxiliary equipment such as water treatment, gas compressor, electrical skid (with optional diesel generator set for "black starting") etc. Final performance data for this model will be made available once comprehensive testing is completed on their prototype in Japan. The two packages described above represent the initial thrust of Cheng Cycle Development. As mentioned at the start, steam injection is not a new concept. However, its successful application in the Cheng Cycle System has prompted several of the manufacturers of larger sized gas turbines to offer significant power augmentation with steam injection. The Cheng Cycle is now a viable and significant option in potential cogeneration applications, and its inherent flexibility and controlability provide many advantages over conventional cogeneration systems, such as a combined cycle power plant which would utilize a gas turbine, waste heat recovery boiler and a steam turbine.

0710H



EQUIPMENT WEIGHTS		
	SHIPPING	OPERATING
TURBINE-GENERATOR SKID	85,000 LB	94,500 LB
INLET FILTER/EVAP. COOLER	—	9,700
SUPERHEATER	30,800	32,800
BOILER	73,500	96,750
ECONOMIZER	25,400	28,270

CONTRACT NO. MOD 4	
DRAWN	FRANK LU
CHECKED	R. [illegible]
ISSUED	F. [illegible]
[illegible]	

INTERNATIONAL POWER TECHNOLOGY
2000 W BAYSHORE, PALO ALTO, CALIFORNIA, USA

CHENG CYCLE SERIES 7 COGEN UNIT
GENERAL ARRANGEMENT,-ELEVATION

FIG. 1

REV. B

IPC-GA-M004-IPT-1-1

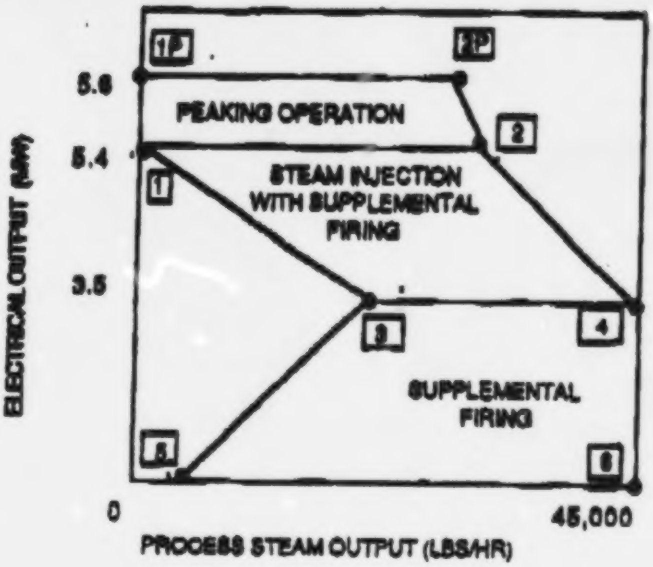


Figure 2 Cheng Cycle Operating Range

Operating Point:	1	2	3	4	5	6	1P	2P
Power Output (kW at Generator Terminals)	5,362	5,362	3,562	3,562	0	0	5,592	5,592
Process Steam Output (Lbs/Hour)	590	36,704	22,731	43,219	4,621	44,994	1,784	36,539
Turbine Fuel (Gas-MMBtu/Hr LHV)	49.21	49.21	44.81	44.81	14.52	14.52	51.28	51.28
Duct. Burner Fuel Gas - MMBtu/Hr LHV)	0	43.19	0	24.49	0	44.75	0	41.68
Injection Steam (Lbs/Hr)	19,800	19,800	0	0	0	0	19,800	19,800

Table 2-1. Series 7 Nominal Operating Performance Specifications-- Gas Fuel

Operating Point:	1	2	3	4	5	6	1P	2P
Power Output (kW at Generator Terminals)	5,221	5,221	3,419	3,419	0	0	5,444	5,444
Process Steam Output (Lbs/Hour)	680	37,048	22,876	43,520	4,621	44,994	1,850	36,891
Turbine Fuel (Oil - MMBtu/Hr)	48.11	48.11	43.72	43.72	14.52	14.52	50.09	50.09
Duct. Burner Fuel (Oil - MMBtu/Hr)	0	43.53	0	24.75	0	44.75	0	42.05
Injection Steam (Lbs/Hr)	19,800	19,800	0	0	0	19,800	19,800	19,800

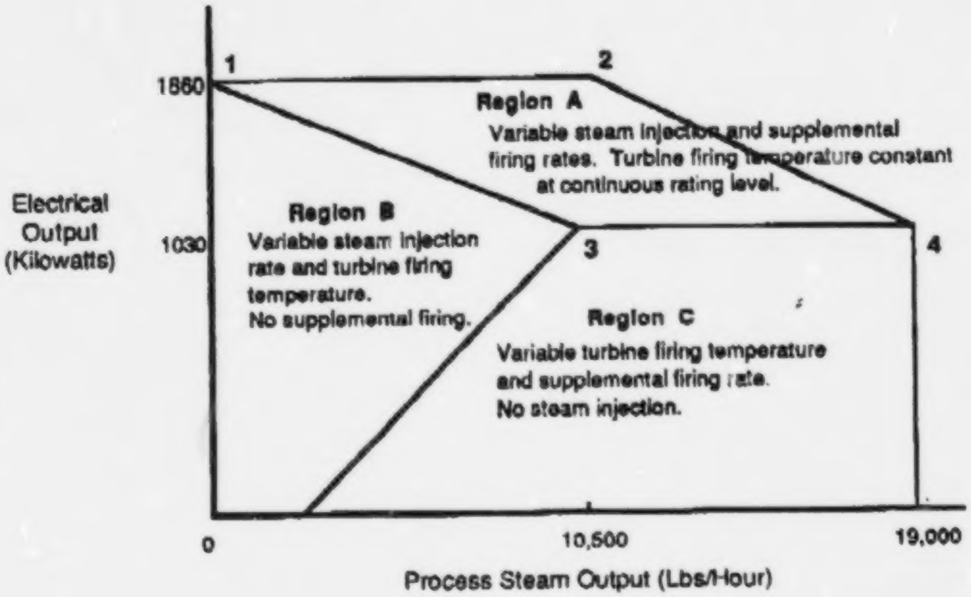
Table 2-2. Series 7 Nominal Operating Performance Specifications-- Oil Fuel

FIG. 3

International Power Technology

Cheng Cycle Series 5-Cogen Operating Regime, Revision 1.0

Cheng Cycle Series 5-Cogen Operating Regime



Operating Point	1	2	3	4
Power Output (kW at Generator Terminals)	1863	1863	1034	1034
Process Steam Output (Lbs/Hour)	0	10,800	10,460	18,970
Turbine Fuel (MMBtu/Hr - LHV)	21.34	21.34	18.05	18.05
Supplemental Burner Fuel (MMBtu/Hr - LHV)	0	10.30	0	7.94
Injection Steam (Lbs/Hour)	9525	9525	0	0

NOTES:

1. All data are for ISO standard conditions (14.7 psia, 59 degF temperature)
2. Process steam at 200 psig. Figures based on 90% condensate return at 170 degF

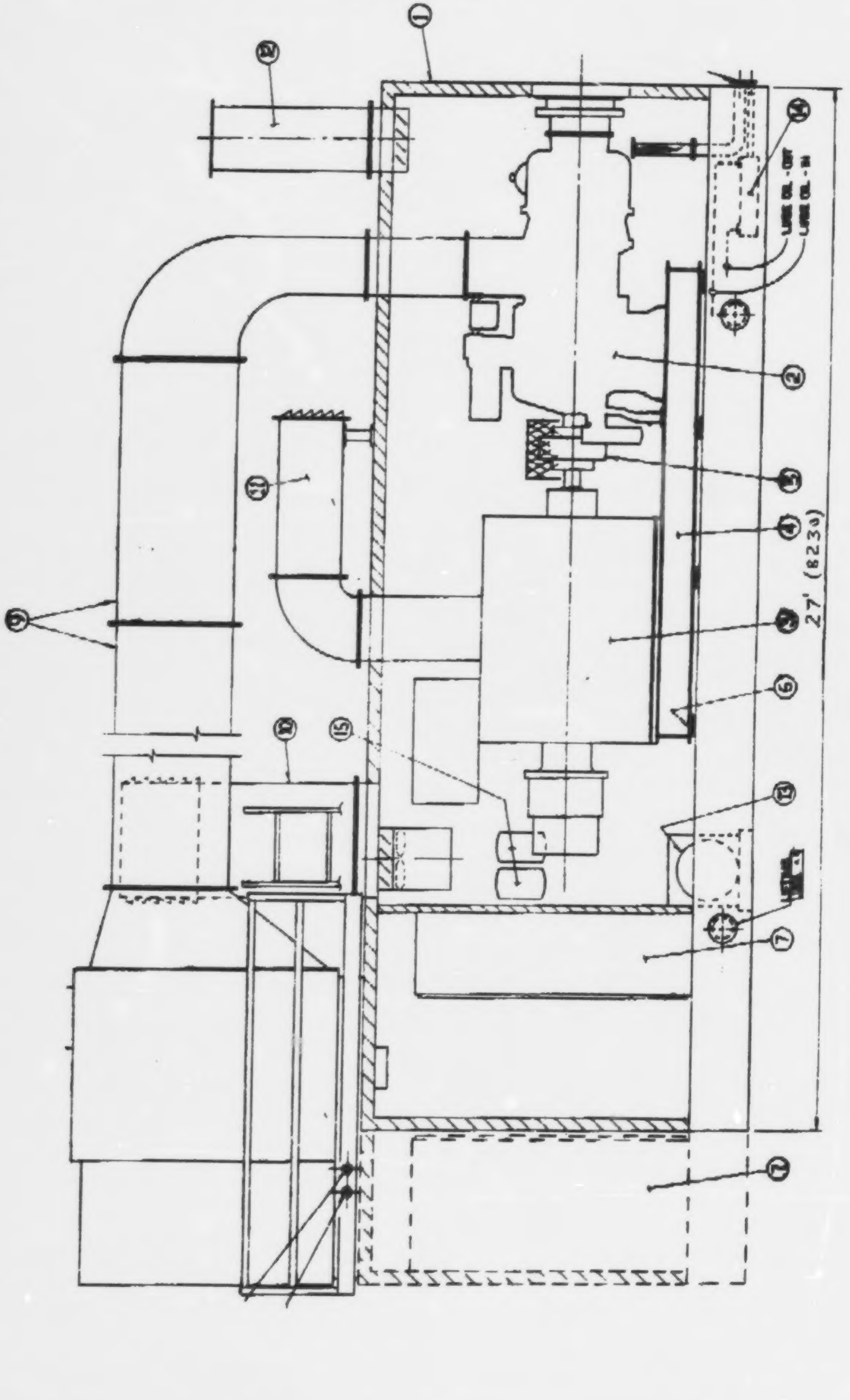
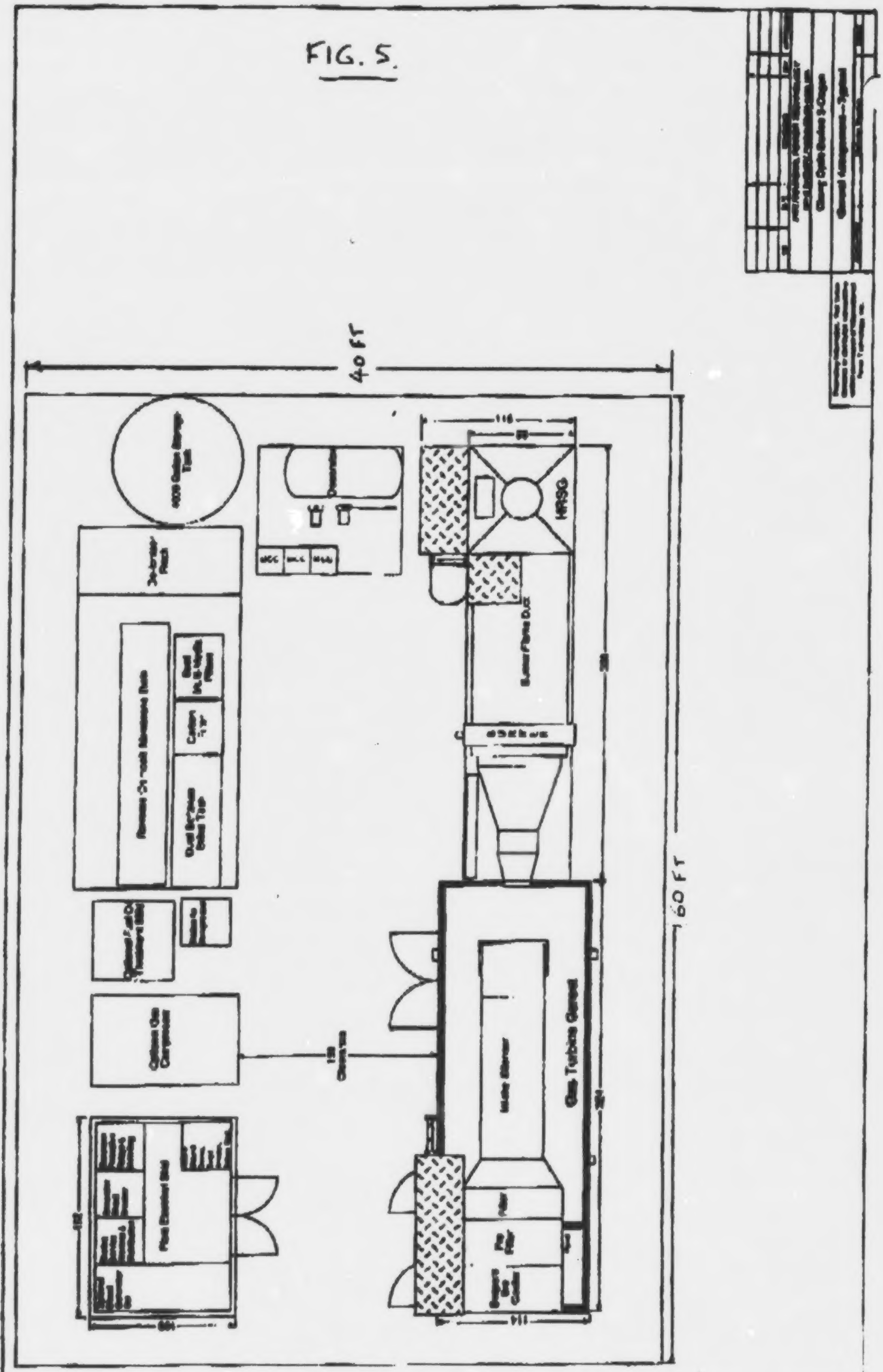

①
⑫
⑪
⑨
⑩
⑮
⑭
LUBE OIL - OUT
LUBE OIL - IN
②
③
④
⑤
⑥
⑬
⑦
⑧
27' (8230)

FIG. 4.

FIG. 5.


40 FT
60 FT
HRSG
118
114

Cogeneration Market Trends in the United States

By
Keith G. Davidson
Bruce A. Hedman
Steven A. Knable
Gas Research Institute

7

COGENERATION MARKET TRENDS IN THE UNITED STATES

Cogeneration Experience and Prospects in Ontario
Toronto, Ontario March 10, 1988

by
Keith G. Davidson
Bruce A. Hedman
Steven A. Knable
Gas Research Institute
8600 West Bryn Mawr Avenue
Chicago, Illinois

The FERC rules implementing Sections 201 and 210 of the Public Utility Regulatory Policies Act (PURPA) unleashed a pent up potential for onsite power generation that had developed as a result of rising energy costs and the thermodynamic diseconomy of separate generation of heat and electricity. Given the significant inroads cogeneration has made into the U.S. market since PURPA was implemented in 1980, it is obvious that the institutional framework implemented as a result of PURPA worked. Some utilities and policymakers are now saying that it worked too well as cogeneration and independent power not only kept up with the demand for new generating capacity in capacity-short regions of the country, but in many cases, added capacity that will not be needed for some time. In any event, cogeneration has proven itself as a competitive generation technology and is likely to remain a sensible and necessary part of the U.S. energy future. Figure 1 illustrates how well cogeneration has done since the enactment of regulatory incentives. In excess of 40,000 MW of cogeneration capacity is operating, under construction, or planned in the United States.[1] This is in addition to the 10-12,000 MW that existed prior to PURPA. By far, the biggest industrial sector player has been the chemicals industry, accounting for approximately 30 percent of the total capacity. Other major industrial sectors with sizeable cogeneration capacity include; enhanced oil recovery, pulp and paper, refining, manufacturing and food.

The cogeneration movement has now reached most parts of the United States. In terms of total capacity, the southern United States has been the leader with more than 10,000 MW of operating or planned capacity. Within the South, the two states that have dominated the activity are Texas and Louisiana. The need for new electric generation capacity, attractive electric buyback rates, and plentiful, cheap gas were all reasons that accounted for the good showing in this region. Inexpensive and efficient, natural-gas-fired, combined-cycle technology was prevalent in this region of the country. The Southwest, most notably California, has also fared well with total capacity of about 9,000 MW.

The robust activity in California was due to attractive economics resulting from favorable retail electric rates, favorable electric buyback rates, and a very supportive state utility commission. The regional dynamics of cogeneration have been interesting to observe, since state utility commissions and electric utilities have a fair amount of control over the rate of cogeneration implementation. Figure 2, which summarizes the regional activity of QF cogenerator filings in 1987, illustrates this point. You can see that activity in the southern and western parts of the United States has slowed considerably. This is due to a temporary over-saturation of cogeneration in those regions resulting in excess capacity, which in turn, resulted in electric utility policies designed to curb the rate of cogeneration growth. However, we see strong movements to the northeastern part of the United States which reflect a pending need for new generation capacity in the early 1990s.

As shown in Figure 3, natural gas continued to maintain a 60 percent market share in 1987, as it has throughout the history of PURPA. This is attributable to low installed cost for natural gas cogeneration equipment, high electric generation efficiencies which permit more megawatts for a given thermal load, and the environmental attributes of natural gas which favors its use over other fuels in many parts of the country. Coal maintains an approximate 35 percent market share with waste fuels accounting for about 5 percent -- waste fuels include black liquor, refinery off-gases and food wastes.

The growth in cogeneration that has taken place through 1986 applies to all system sizes as shown in Figure 4. Note the slight reduction in all capacity sizes in the year 1987 with the exception of the very large (greater than 100 MW) systems. This reduction can be attributed to two factors. First, the implementation of less favorable tax depreciation treatment for cogenerators, and second, the conscious attempt on the part of many electric utilities to discourage the implementation of cogeneration. Tactics that are being adopted by electric utilities attempting to discourage cogeneration development include increased standby rates for backup power and *deferral* rates whereby the electric utility gives selected customers reduced rates in turn for a commitment to defer construction of a cogeneration facility for a specified length of time.

Compared to accumulated capacity size distribution, the very large cogenerators represented a larger share of the activity in 1987 as shown in Figure 5. This is due to the opening up of new markets in the eastern and northeast parts of the United States and the generally negative environment that has begun to pervade many other parts of the country. Anti-cogeneration initiatives often impact the smaller cogeneration facilities the hardest because they cannot absorb the "soft" costs associated with fighting the institutional obstructions.

In terms of numbers of sites, smaller cogeneration facilities have experienced rapid growth through 1986 as shown in Figure 6. To date, the most common applications for small cogeneration equipment have been light industrial facilities, health clubs, hotels, hospitals and nursing homes, schools, multi-family dwellings and data processing centers as illustrated in Figure 7. Although the total megawatt contribution from these small cogeneration facilities has not been significant to date, the sheer number of potential sites is staggering. If appreciable gains in the cost economy of the technology in this size range can be made, the potential contribution to cogeneration capacity by the commercial sector could be very sizeable.

Summarizing the institutional and regulatory environment in the United States, PURPA remains intact while, at the same time, anti-cogeneration rates are becoming more common among the electric utilities. States and electric utilities are searching for a mechanism to better control the rate of implementation of cogeneration. There is a movement ongoing towards competitive bidding and open access to the electric transmission system which, if implemented to the limit, would make available all options for electric generation capacity whenever there is a need for new capacity.

U.S. ENERGY OUTLOOK

Figure 8 illustrates the need for utilities to initiate construction of additional new power plants beginning in the mid 1990s. By the year 2010, about 200 GW of new capacity above that included in current utility plans will be required. It should be noted that locally, shortfalls could begin to occur in the early 1990s. The requirements for additional capacity will be disproportionately weighted towards peaking and intermediate service needs which represents an opportunity for natural gas-fired generation equipment.

The long term availability of competitively priced gas is obviously a key factor in determining the role natural gas will play in the future.

The first thing one must remember is that U.S. gas consumption shrank from 22 trillion cubic feet (Tcf) in 1973 to only 16.2 Tcf per year in 1986, and that most projections call for little increase in annual gas demand unless a substantial increment for power generation can be realized. The reason is that energy conservation is still offsetting gains in new gas customers and new gas uses in the buildings sector, and that the ongoing restructuring of U.S. industry continues to depress all of its energy requirements as a competitive global economy dictates location of manufacturing capacity where labor, energy, and raw material costs are cheapest.

While demand for gas remained relatively disappointing, 1986 reserve additions were amazingly robust. Approximately 89 percent of total U.S. production and 96 percent of Lower-48 production were replaced even with rig counts approaching postwar lows. A recent study of the Colorado School of Mines sponsored by the Gas Research Institute (GRI) and the Electric Power Research Institute (EPRI) indicated that, on the basis of a set of quite reasonable economic and resource base assumptions:

- At *marginal* costs of up to only $1 per Mcf, 156 Tcf of the remaining unproven (potential) Lower-48 resources could be recovered, and at up to $3 per Mcf, this increases to 393 Tcf.

- At an *average* cost of up to $3 per Mcf, recoverable potential Lower-48 resources increase to 535 Tcf.[2]

These costs are in terms of 1980 dollars and would be about one-third higher in 1986 dollars. However, this still presents an extremely reassuring picture, especially since the potential volumes cited above *exclude* proven reserves and the favorable impact of advanced technologies on recovery of gas from unconventional reservoirs.

Of course, promising resource data such as these do not necessarily ensure sufficient low-cost gas development. Some producers seeking low-cost gas will be forced to take reduced rates of return or walk away from uneconomic discoveries. Producer behavior will also be influenced by existing activity in the field, exploration already done, and the inflexibilities imposed by lease positions. In its modeling efforts, GRI attempts to simulate these dynamics on the presumption of rational producer behavior. At a minimum, real after-tax rate of return of 10 percent at oil prices corresponding to those noted before and corresponding producer price expectations for deregulated gas, GRI projects Lower-48 production capabilities *without* further advances in enhanced recovery technologies of about 16 Tcf in 1990, declining to about 14 Tcf in 2000. However, it is confidently expected that demand levels in the 19 Tcf range can be met through 2010 - nearly 3 Tcf above 1986 demand - with the added contributions from enhanced recovery technologies, the growing Canadian export potential, and other economically viable supplemental sources.

But this tells only part of the favorable potential gas supply story. GRI's assessment indicates that somewhere between 400 and 450 Tcf of the remaining Lower-48 gas resource base can be recovered profitably with existing technology at marginal costs of up to $4 per Mcf (1986 dollars), including the current 160 Tcf of proven Lower-48 reserves. An additional 170 Tcf could be recovered from tight formations at marginal costs up to $4 per Mcf with the new enhanced recovery technologies now under intensive development. This raises the total that could be delivered at up to $4.50 per Mcf to roughly 600 Tcf - more than 35 years of consumption at a hoped-for demand of 19 Tcf per year of which an average of roughly 2 to 2.5 TCF per year is met by imports. Even if our fondest hopes for continued growth of gas-fired cogeneration materialize, this should still leave about 2 Tcf per year of spare supply capability - enough for about 50 GW of base load combined-cycle capacity or 100 GW of intermediate-load capacity.[2]

GRI believes that a sufficient resource base exists to ensure that gas-fired cogeneration can remain an attractive power supply option well into the next century. Figure 9 summarizes GRI's view of the future of cogeneration in the United States.[3] Taken from the 1987 GRI Baseline Projection of energy supply and demand, it shows that industrial cogeneration is expected to more than double from just over 21,000 MW of installed capacity in 1986 to over 44,000 MW in 2010. About 60 percent of this total capacity in 2010 will be gas-fired.

Given expected technology improvements, cogeneration or the commercial sector should increase from under 1,000 MW of installed capacity in 1986 to almost 15,000 MW in 2010 -- almost all of this will be gas-fired. Based on this outlook, cogeneration and small power producers will provide an increasing share of this nation's electricity requirements as illustrated in Figure 10.

One final comment should be made on the importance of technology developments on the future of cogeneration. Although regulatory and marketplace factors are helping spur the use of gas-fired cogneration technologies, successful completion of R&D efforts currently underway will extend their application even further. GRI's R&D on cogeneration and power systems technology is directed at achieving improvements in efficiency, durability, maintenance requirements, ease of integration, and flexibility of operation compared to presently available technology. Such improvements will enhance the value of cogeneration in existing applications, extend the benefits of cogeneration to a wider range of potential applications and ensure that gas-fired cogeneration remains a cost-effective option over the forseeable future.

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2. H. R. Linden, "The Case for Increasing Use of Natural Gas in Electric Power Generation," in *Public Utilities Fortnightly*, February 18, 1988, pp. 24-29.
3. P. D. Holtberg, T. J. Woods, and A. B. Ashby, "1987 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010," *Gas Research Insights*. Chicago: Gas Research Institute, December 1987.

COGENERATION CAPACITY OPERATING AND PLANNED

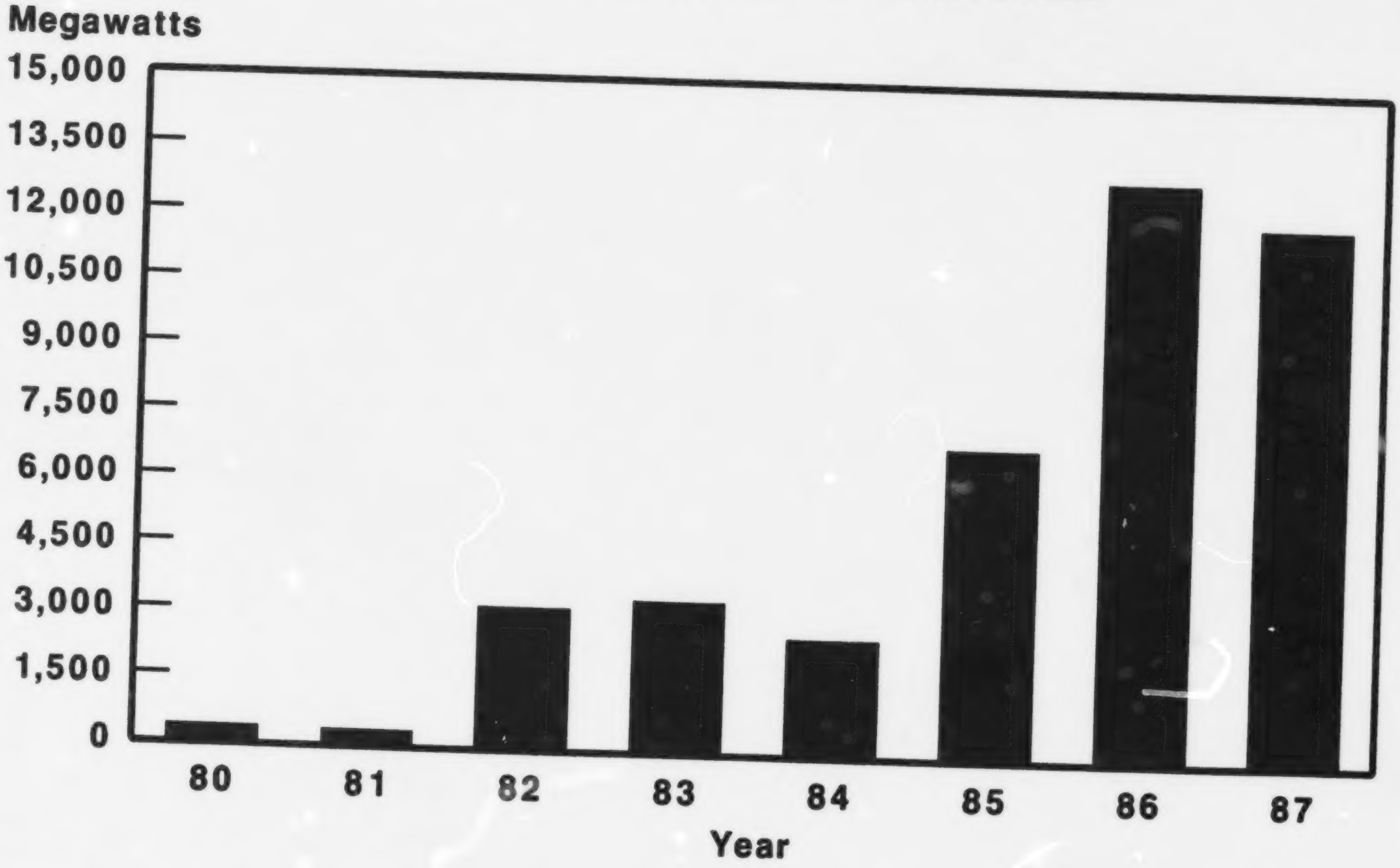

Figure 1

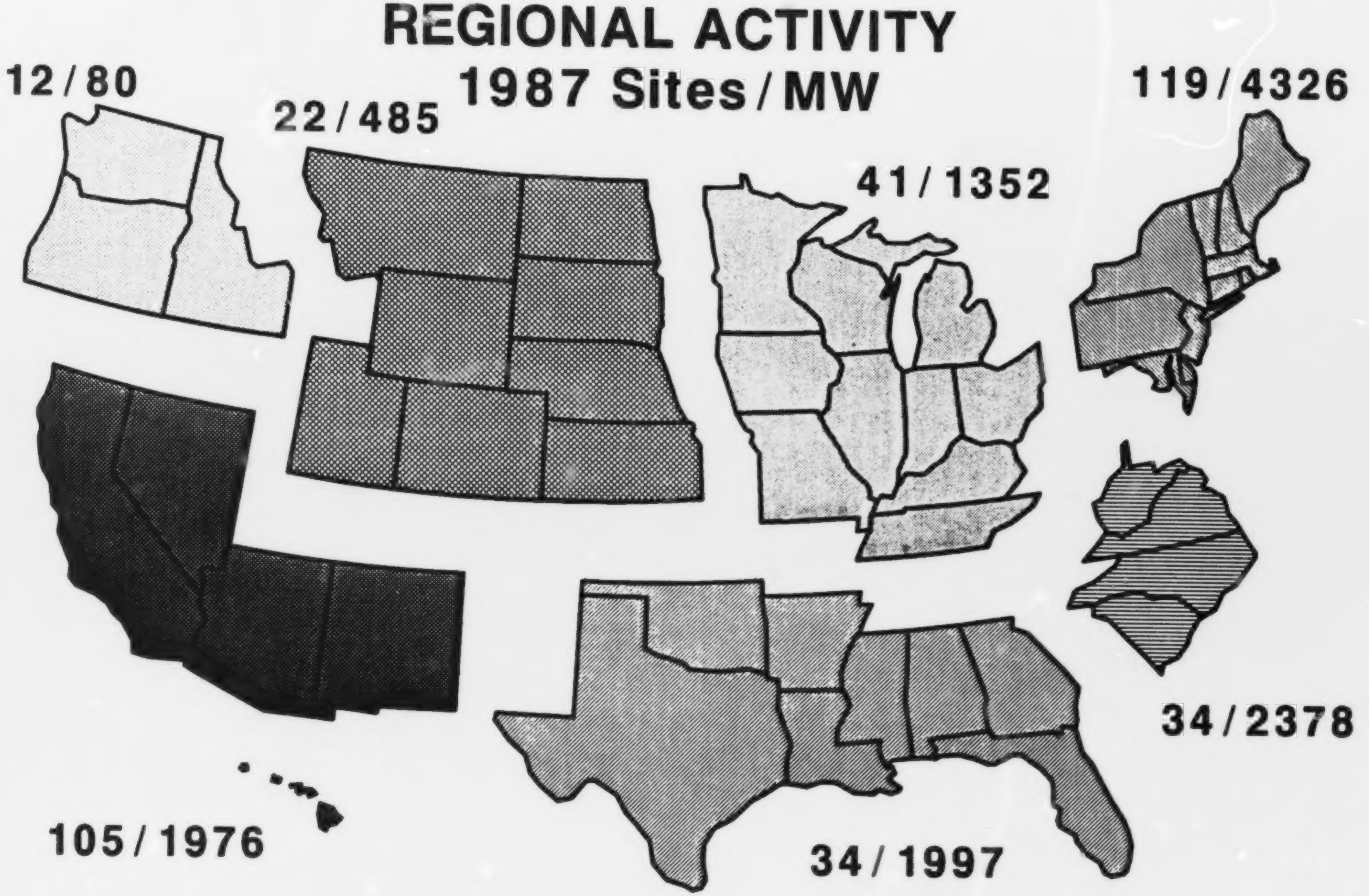
REGIONAL ACTIVITY
1987 Sites / MW
12 / 80
22 / 485
119 / 4326
41 / 1352
34 / 2378
105 / 1976
34 / 1997

Figure 2

COGENERATION FUEL USE
1987 Activity Only

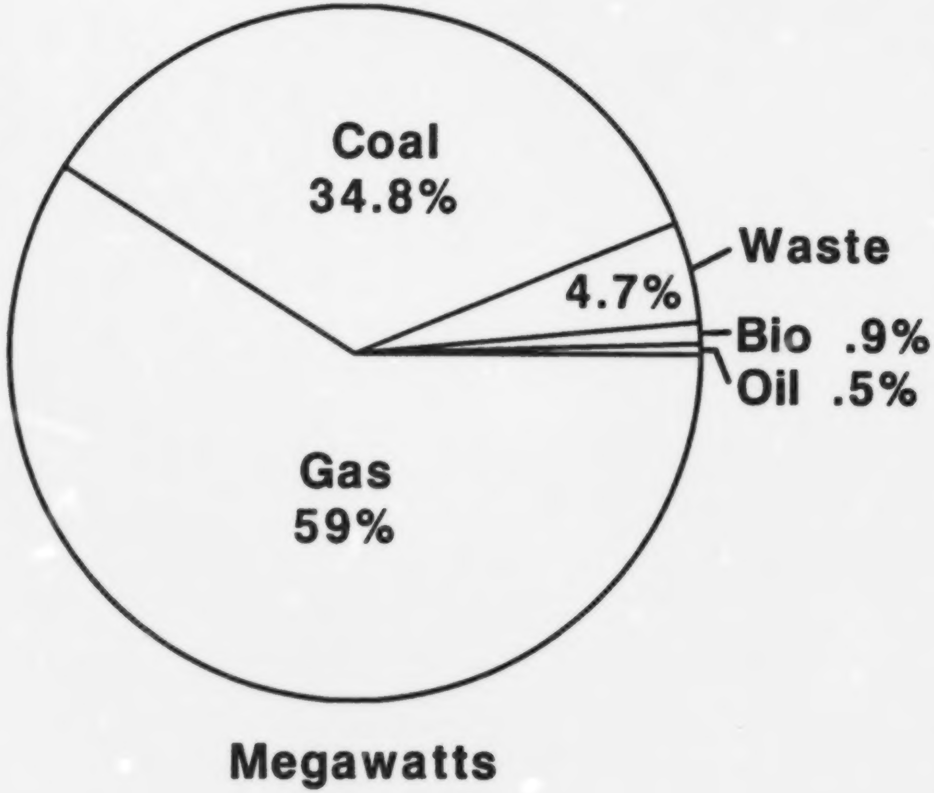

Figure 3

COGENERATION INSTALLED CAPACITY

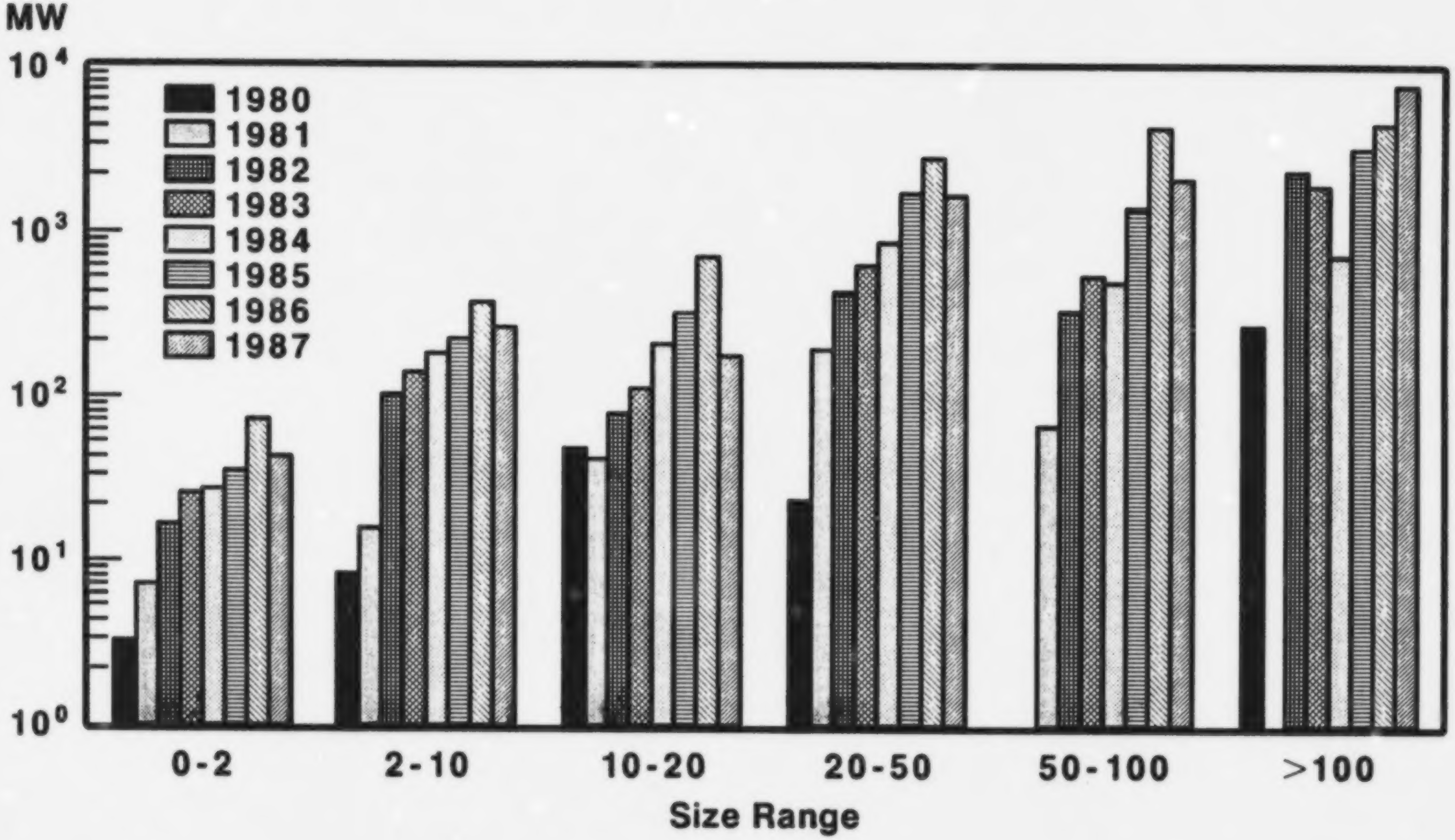

Figure 4

CAPACITY BY SIZE DISTRIBUTION

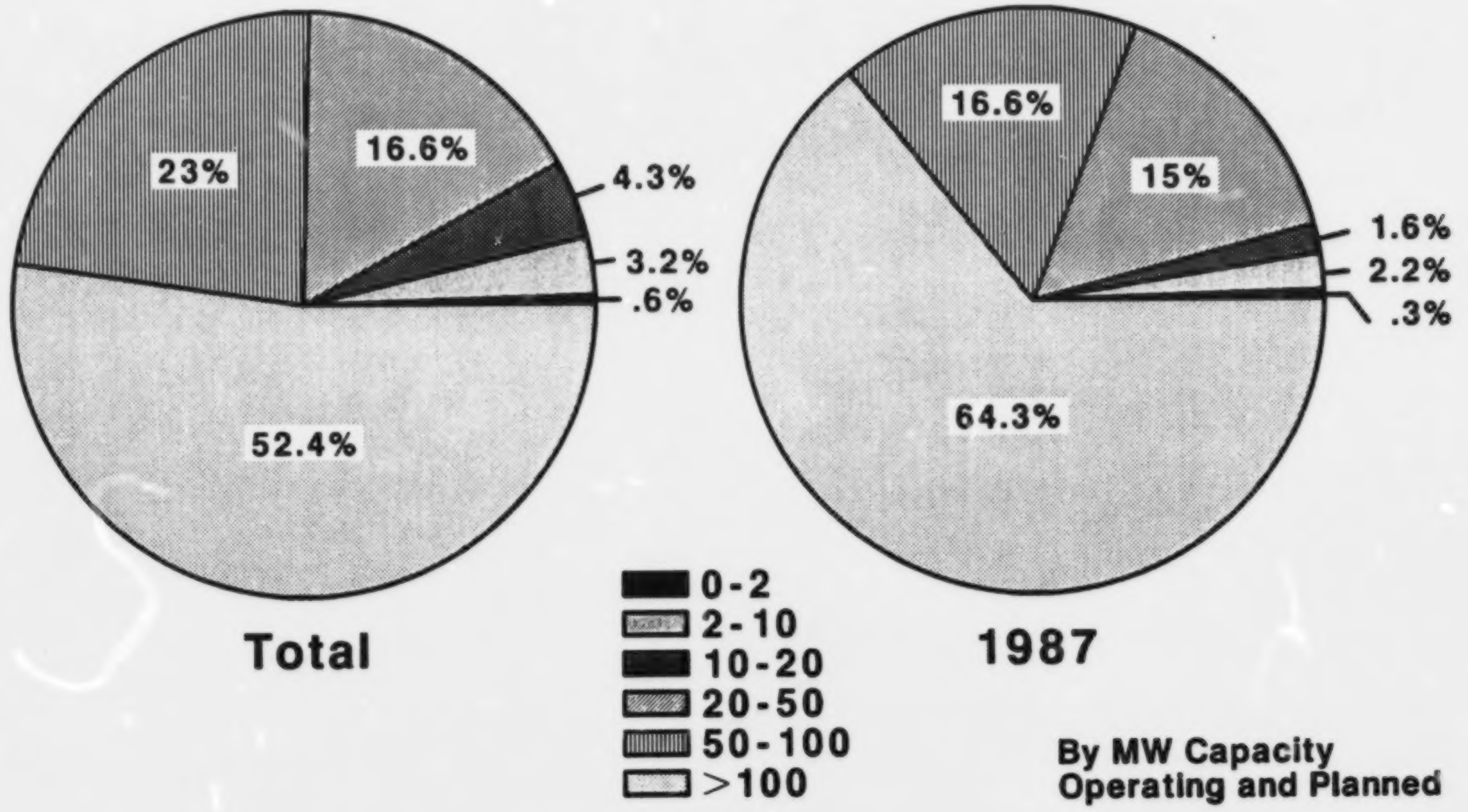

Figure 5

COGENERATION INSTALLATIONS COMMERCIAL AND INDUSTRIAL

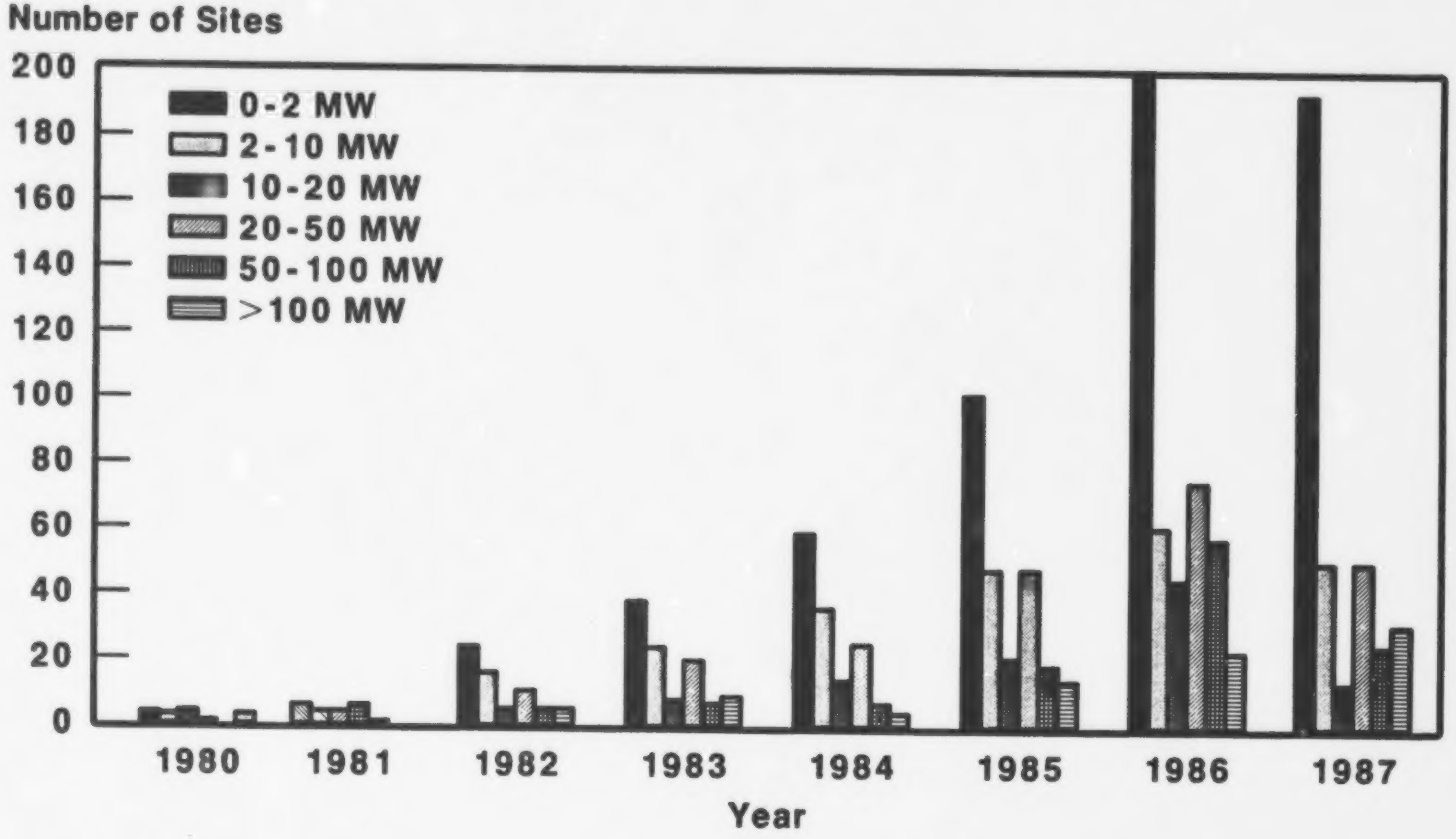

Figure 6

SMALL COGENERATION ACTIVITY BY APPLICATION

Less Than 2000kW Capacity

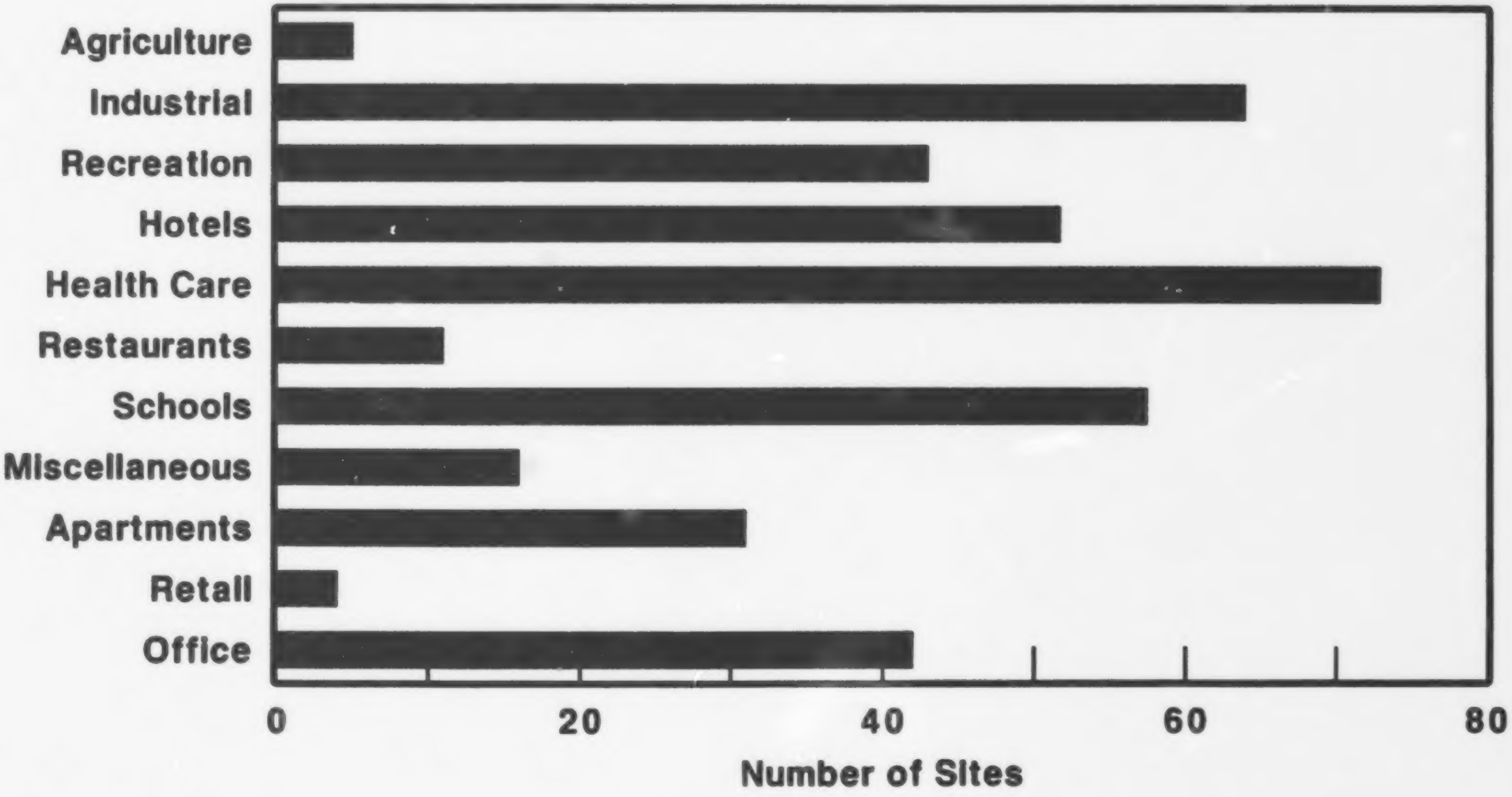

Figure 7

EXPECTED ELECTRIC UTILITY GENERATING CAPACITY

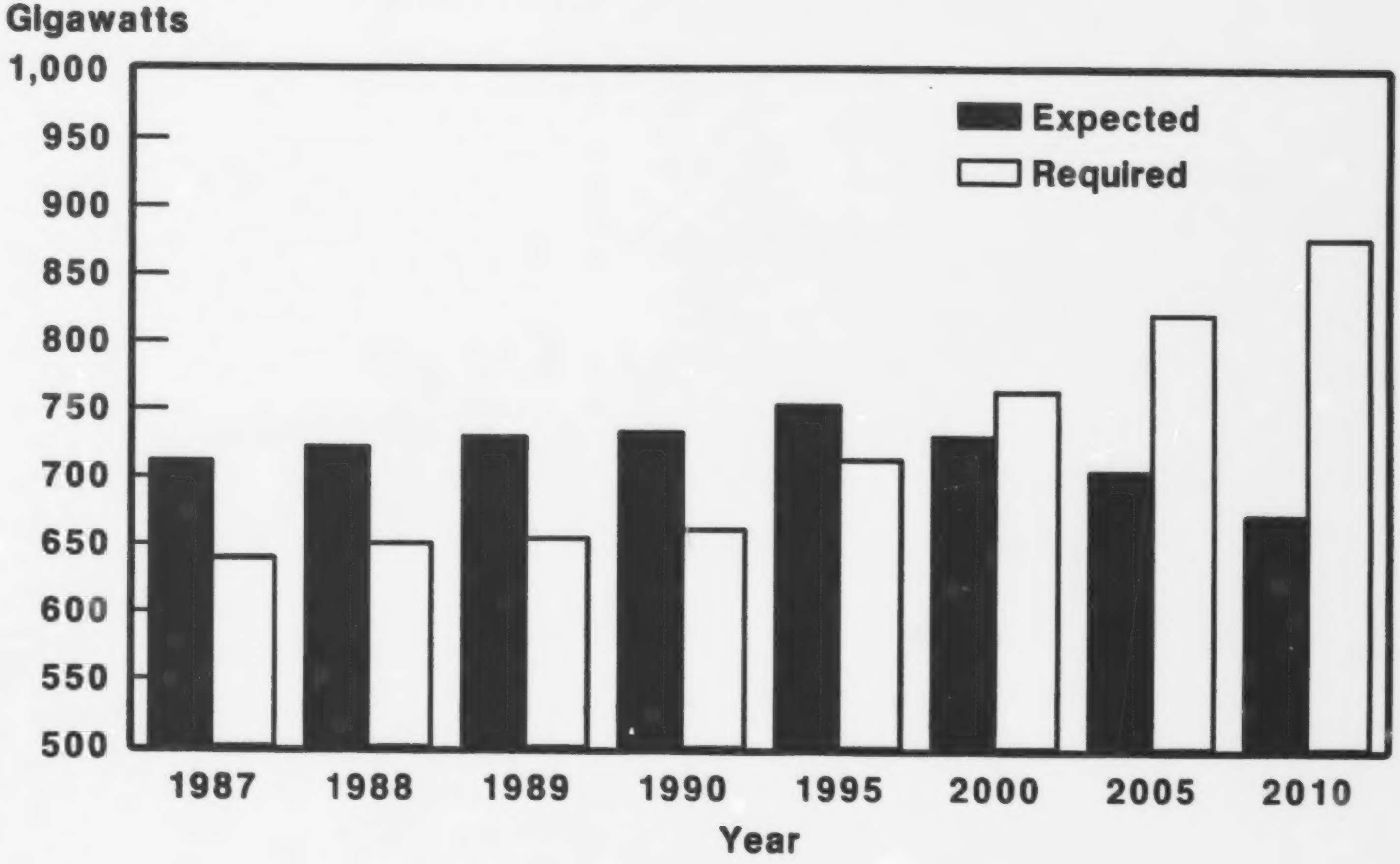

Figure 8

COGENERATION PROJECTIONS
INDUSTRIAL & COMMERCIAL

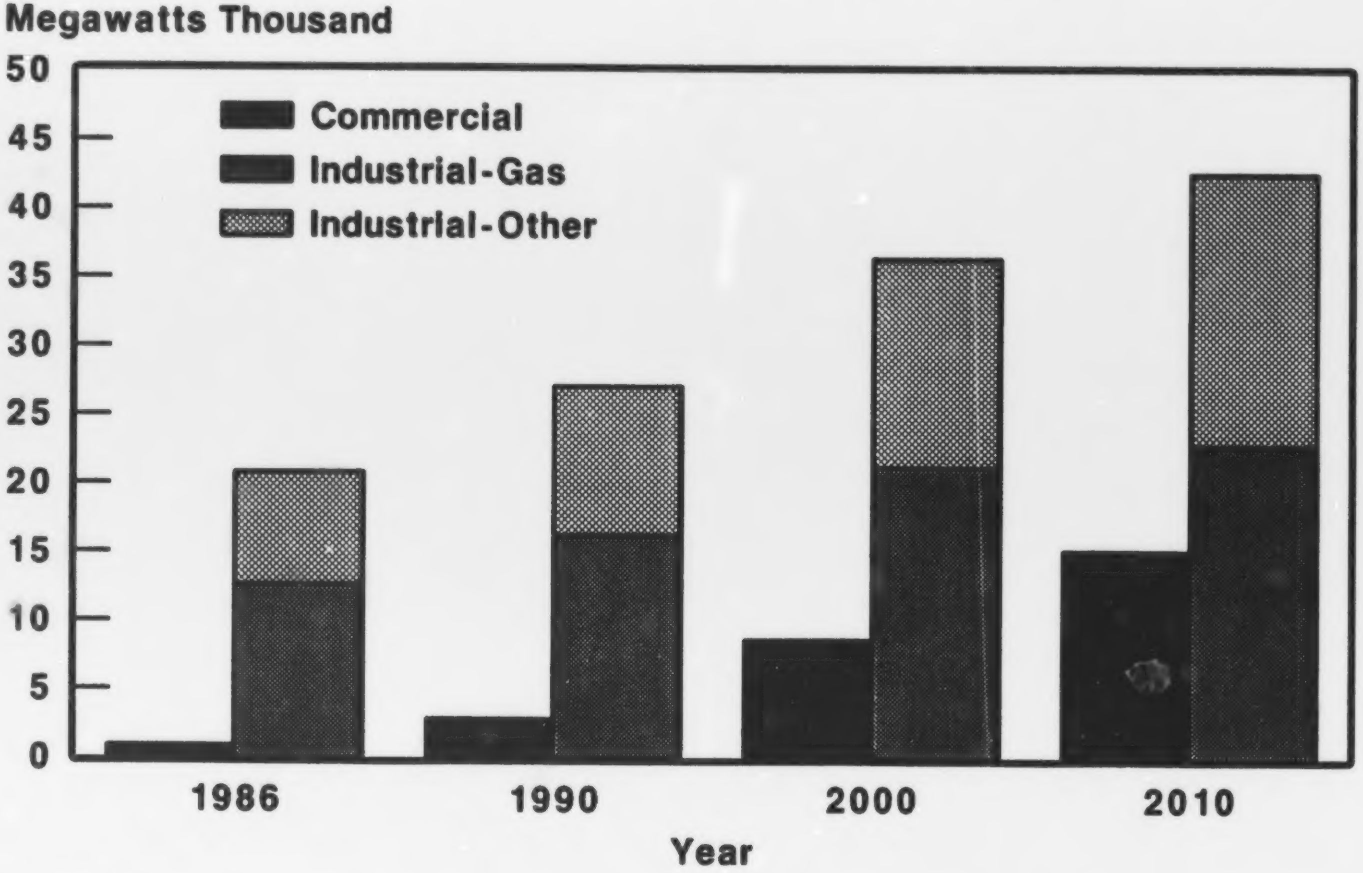

Figure 9

SOURCES OF END-USE ELECTRICITY
(Quads)

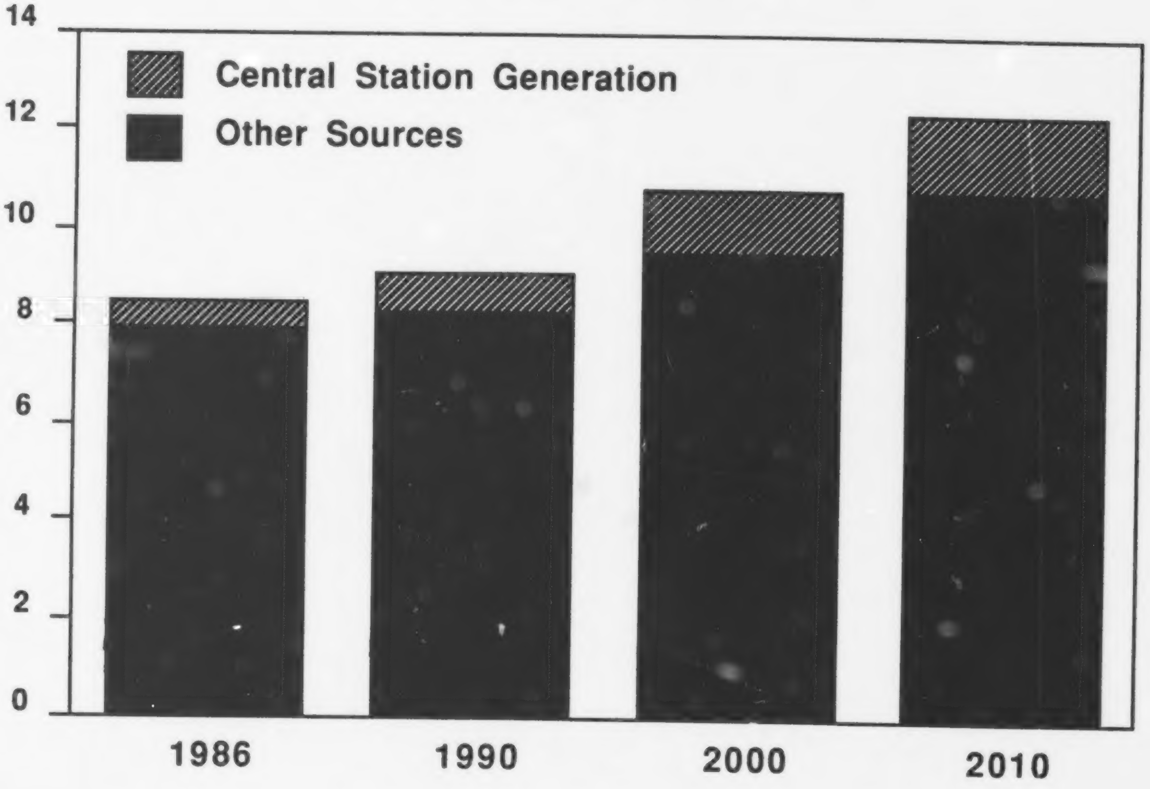

Figure 10

TransCanada Pipelines Ltd.

By
F. Greflund
TransCanada Pipelines Ltd.

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PRESENTATION TO THE COGENERATION SEMINAR
MARCH 10, 1988, TORONTO, ONTARIO

Presented by: F. Greflund, P.Eng. - TransCanada Pipelines Ltd

TransCanada's Dual Power Project at Nipigon, Ontario is a modified combined cycle plant which produces both electric and gas compression power for sale to Ontario Hydro and TransCanada Pipelines Ltd, respectively. It is proposed that the dual power plant be owned and operated by a wholly owned subsidiary of TransCanada PipeLines.

Before describing the project, I would like to briefly outline TransCanada's operations. We are the owners and operators of 10,000 Km of large diameter gas pipeline stretching from the Alberta border to Vermont. TransCanada has about 750,000 kW of total installed compression power at fifty compressor sites along the pipeline. The daily volume moved by TransCanada is 85 million cubic meters (3 BCF).

TransCanada's interest in electric power generation goes back over many years when power projects were first evaluated as a means of diversifying into non-regulated business activities. Initial exposure to power generation projects came from the Northeastern United States where TransCanada had been marketing gas for some time.

Several New England electric utilities together with TransCanada formed the Ocean State Power Project. TransCanada is a 40% equity participant and co-developer of the 240 MW combined cycle Ocean State Power project in Rhode Island.

In Canada, we began exploring combined cycle/cogeneration business opportunities and identified Northwestern Ontario as a region where Ontario Hydro were actively promoting large scale parallel generation. The incremental power requirements in Northwestern Ontario coupled with TransCanada's need to replace some of its aging fleet of gas turbine compressors formed the basis of mutual benefit for both Ontario Hydro and TransCanada.

TransCanada identified a compression need of 12-14 MW which permitted about 41 MW of electric power to be generated as shown in Figure 1. Nipigon, Ontario was chosen as the site for the dual power project, the reasons being:

- the station is presently a bottleneck in the gas transmission system which is unable to meet the maximum discharge pressure of 7240 kPa (1050 psig);
- the location is about 500 m from Hydro's 115 kV transmission system.

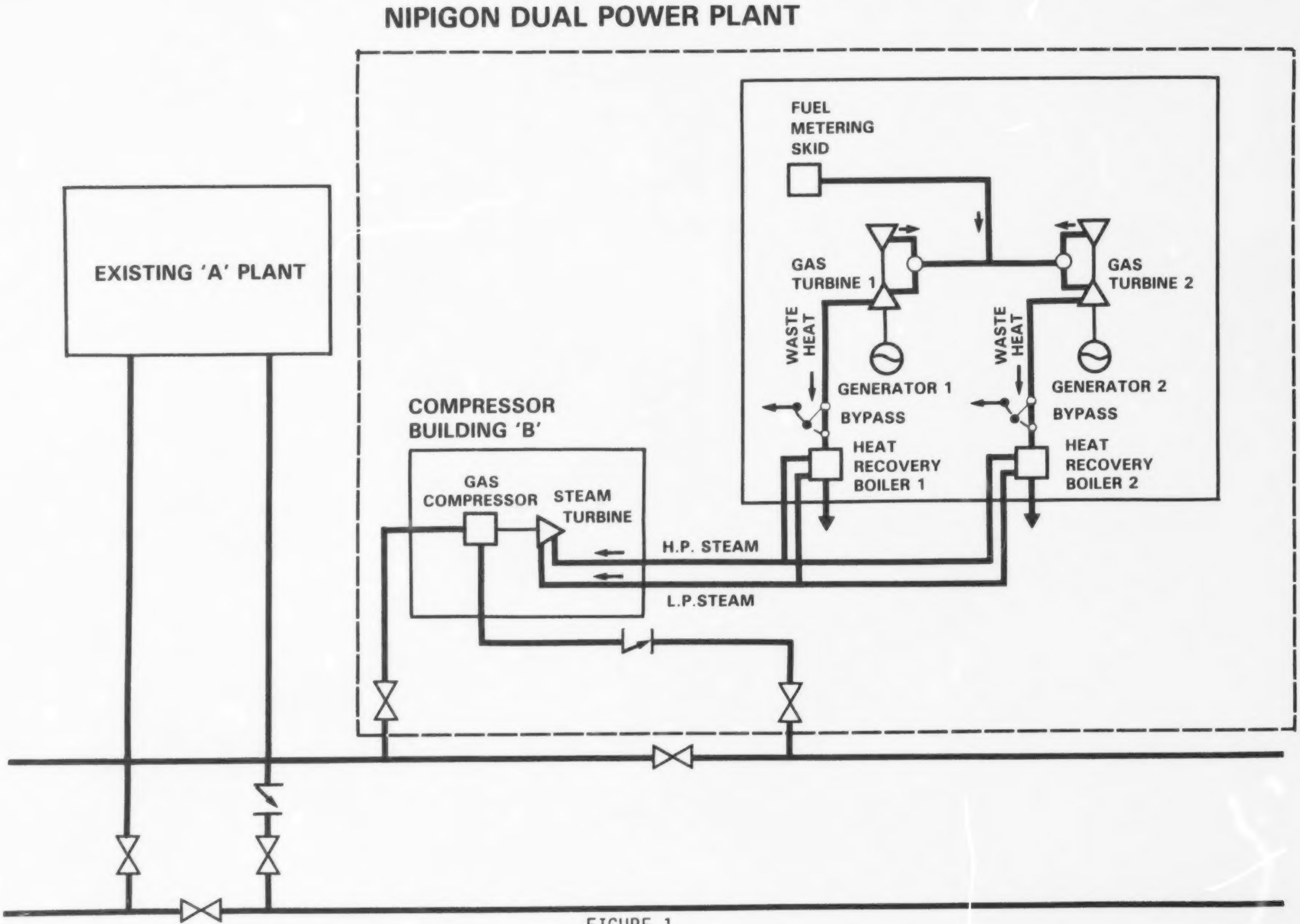
NIPIGON DUAL POWER PLANT
EXISTING 'A' PLANT
FUEL METERING SKID
GAS TURBINE 1
GAS TURBINE 2
WASTE HEAT
WASTE HEAT
GENERATOR 1
GENERATOR 2
BYPASS
BYPASS
HEAT RECOVERY BOILER 1
HEAT RECOVERY BOILER 2
COMPRESSOR BUILDING 'B'
GAS COMPRESSOR
STEAM TURBINE
H.P. STEAM
L.P.STEAM

FIGURE 1

In addition to TransCanada's need for incremental new compression, the project offers the following advantages:

- reliable incremental power;
- availability in excess of 92%;
- capacity can be tailored to demand;
- existing Hydro transmission system is in place;
- environmentally benign;
- short lead time to construct of two years.

As Figure 1 indicates, the dual power plant will compress gas in parallel with the existing "A" plant. Although the "A" plant can justifiably be retired, it is intended that the it be left as a stand-by plant at no cost to the pipeline toll payer. This offers the benefit of "free" stand-by power at this critical location.

For the purpose of our study we chose two aero derivative gas turbine generator sets each driving a 20.5 MW generator. The gas turbines will each have a dedicated dual pressure heat recovery steam generator complete with bypass. Steam is piped to a condensing steam turbine in the compressor building where pipeline gas is compressed to about 7240 kPa (1050 psig) a Δ P of 1030 kPa (150 psig). Exhaust steam is condensed in air cooled condensers.

The plant will be interconnected with TransCanada's gas control center and will be dispatched as a base load unit.

The Engineering and Performance Data can be summarized as follows:

- 2 - Gas turbine-generator sets - Dresser Rand GT61 - 20.5 MW ea. (used for study purposes)
- 2 - Heat recovery steam generators - Dual pressure, unfired
- 1 - Condensing turbine and gas compressor - 14.5 MW (shaft)
- Air cooled condenser - 122.4 GJ/hr (129 x 10^6 BTU/hr) heat rejection
- 1 - lot switchgear and transformer

Fuel consumption - 102 x 10^6 m^3/annum (3.6 BCF)
Gas turbine heat rate - 10,765 BTU/kWh
Overall plant heat rate - 8060 BTU/kWh
Net Electric Power - 330 GWh/annum
Compression power - 117 GWh/annum
Average utilization - 92%

Based on the major equipment selected, a turnkey contract for the entire plant including tie-in to the pipeline and Hydro's 115 kV line was estimated to cost $60 MM (1987) with an annual O&M cost of $2.8 MM (1987). The project economics were calculated taking into account that part of the plant which qualifies as Capital Cost Allowance Class 34 - accelerated depreciation.

The contractual arrangements which govern the project are obvious from Figure 1. The contracts currently under negotiation between the Project and other parties are as follows:

- Electric Power Sale - Ontario Hydro to purchase 330 GWh/annum over 20 years.
- Gas Purchase - Western Gas Marketing Limited to supply 102×10^6 m^3/year over 20 years.
- Compression Power Sale - TransCanada PipeLines to purchase 117 GWh/year of compression power over 20 years.
- Gas Transportation - TransCanada PipeLines will provide gas transportation to the Nipigon site.

The Dual Power project meets the requirements of a potentially successful project in that all parties stand to benefit as follows:

TransCanada PipeLines

- Non-regulated business activity;
- Incremental gas transportation.

Ontario Hydro

- Long term, reliable and economic power delivered at Hydro's avoided costs.
- Security of power supply - "must run" units.
- Displace need for additional electric power generation or supplies to Northwestern Ontario.
- Demonstration project - other opportunities exists along the pipeline.

Pipeline Toll Payers

- Held "whole" in project costs (compression rates are NEB approved).
- Existing "A" plant will not be retired thus giving toll payers excess capacity and stand-by capacity for "free".

M12/FG5

Gas Producers

- Incremental gas sale.
- Long term gas contract with guaranteed yield.

The schedule of contract negotiations and selection of turnkey contractor is relatively short. However, it is expected that the project will be in service by mid-1990.

Cogeneration Case Study
Backpressure Turbine Generator
for
H.J. Heinz Company of Canada Ltd.

By
Ken Hubley, P.Eng.
Monenco Consultants Limited

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COGENERATION CASE STUDY
BACKPRESSURE TURBINE GENERATOR
FOR
H.J. HEINZ COMPANY OF CANADA LTD

PRESENTED AT A
COGENERATION SEMINAR
MARCH 10, 1988
SPONSORED JOINTLY BY:

MINISTRY OF ENERGY, ONTARIO
CONSULTING ENGINEERS OF ONTARIO
ONTARIO NATURAL GAS ASOCIATION

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2. TECHNICAL FEASIBILITY

3. ECONOMIC FEASIBILITY

4. RECOMMENDATION

1. INTRODUCTION

H.J. Heinz recognized early in 1986 the potential opportunity which existed to use a portion of their total process steam reuirement to generate electricity before being used in the process. To investigate this opportunity, H.J. Heinz applied for and received a grant through the Ministry of Energy's Industrial Energy Services Program to partially fund a preliminary feasibility analysis.

Monenco Consultants Limited and Charles G. Turner and Associates were selected to perform the analysis. Monenco acted as lead consultant with C.G. Turner providing specialist input on the boiler plant.

The analysis involved the following activities, the results of which will be reported on during my presentation:

- Technical Feasibility
  - load duration diagram
  - boiler modifications
  - turbine generator options
  - electrical system analysis
- Economic Feasibility
  - project costs
  - project savings
  - cost/benefit analysis
- Recommendation
  - selected option

2. TECHNICAL FEASIBILITY

- Load Duration Diagram

The H.J. Heinz, Leamington plant exhibits the following annual process requirements:

- Process steam:

Process steam used, lb/y	929,300,000
Peak Steam flow range, lb/h	150,000 - 425,000
No. of hours per year,	1000
off peak steam flow range, lb/h	50,000 - 150,000
No. of hours per year,	6600

- Electrical Requirements:

Peak demand, kW	4,000
Energy required, kWh/y	22,000,000

As expected, when the process steam demand increases the electrical energy requirements increase also.

A load duration diagram for the process steam requirements is shown in Figure 1. The diagram was used to determine the amount of electrical energy which could be produced by the process steam flow available.

o Boiler Modifications

The boiler plant consists of 8 boilers ranging in age and output from 10 to 60 years and 45,000 to 160,000 lb/h respectively. Only the newest boiler rated at 160,000 lb/h was considered suitable for upgrading to a higher pressure and temperature operation.

Two upgrading options were considered:

- pressure increase to 275 psig and addition of a super heater to produce steam at 500 °F
- pressure increase to 275 psig to produce dry and saturated steam

The first option proved to be technically and economically unattractive. The concerns included:

- advice against the addition of a superheater by the OEM
- convective versus a radiant design - the former involved major changes to the heating surfaces and both increased heat release rates above recommended values which would increase the probability of occurence of boiler hot spots and decrease boiler life
- installation of a separately fired superheater was considered prohibitive from a capital cost and control perspective.

The second option was thus selected with minimal changes to existing plant. These changes include:

- installation of a new boiler feedwater pump
- re-registration of the boiler feedwater piping
- boiler instrumentation and control changes
- boiler safety value changes

- Turbine Generator Options

A turbine generator performance specification was prepared and issued to eight suppliers. For technical and economic reasons only two suppliers could meet the requirements. One supplier offered a single stage machine, the other supplier offered a multistage machine. Each machine was evaluated for the two steam conditions noted previously even though the superheater option is not feasible. In addition, each option was further evaluated assuming boiler No. 8's load factor remained unchanged or increased to the maximum level practical (see Case 1 and 2 on Figure 1).

The output from the turbine generator set is shown on Figure 2 for each option. As expected the multistage machine, Options 3 and 4, produces a higher output, for example at 130,000 lb/h, the power outputs are:

Option 1	1120 kW
Option 2	960 kW
Option 3	1800 kW
Option 4	1640 kW

The output curves and load duration curve's were combined to determine the total annual power, kWh that each option can produce. These values are:

	Case 1	Case 2
Option 1	4,300,000	7,500,000
Option 2	3,900,000	6,700,000
Option 3	6,100,000	10,200,000
Option 4	5,500,000	9,100,000

The generated power ranges from a low of 3,900,000 to high of 10,200,000 or 17.7% and 46.3% of the total annual power consumption of 22,000,000 kWh respectively.

- Electrical System Analysis

The impact of the generator on the existing electrical distribution system was asessed. Two studies were performed, a short circuit and protective relay coordination study.

The short circuit study concluded that the existing electrical distribution system and equipment has adequate fault capacity to withstand the additional fault current which could be imposed by the generator.

Using the short circuit data resulting from the short circuit study, the protective relay co-ordination study revealed that co-ordination problems exist with some of the existing protective devices.

A conceptual protection and interconnection single line diagram is shown in Figure 3.

3. ECONOMIC FEASIBILITY

o Project Costs

Total installed costs including material, labor and design engineering were developed for each option as follows:

Option 1, Single stage with Superheater	$1,200,000
Option 2, Single stage without Superheater	$ 800,000
Option 3, Multistage with Superheater	$1,600,000
Option 4, Multistage without Superheater	$1,200,000

In specific terms using the power outputs given previously, these costs are:

Option 1	$1071/kW
Option 2	$ 833/kW
Option 3	$ 889/kW
Option 4	$ 732/kW

Other project costs which were included in the cost/benefit analysis are:

- maintenance costs at 1.5 mils/kWh
- tax burden on the savings
- increased natural gas costs to generate steam at higher conditions

o Project Savings

The project savings include the cost of displaced electrical energy presently being supplied by the Leamington PUC, generated by the turbine generator. The first year savings are:

	Case 1	Case 2
Option 1	$ 79,000	$144,000
Option 2	$148,000	$252,000
Option 3	$154,000	$255,000
Option 4	$212,000	$352,000

- Cost/benefit Analysis

The economic evaluation period was set at 10 years and with realistic escalation rates for the cost of capital, electricity, natural gas and maintenance rates, the payback period after taxes for each option is as follows:

	Payback Period, Years	
	Case 1	Case 2
Option 1	9.3 (15.2)	6.4 (8.3)
Option 2	5.0 (5.4)	3.2 (3.2)
Option 3	7.7 (10.4)	5.3 (6.3)
Option 4	5.1 (5.7)	3.3 (3.4)

The values in brackets represent the simple payback periods i.e. project total installed costs divided by the first year savings.

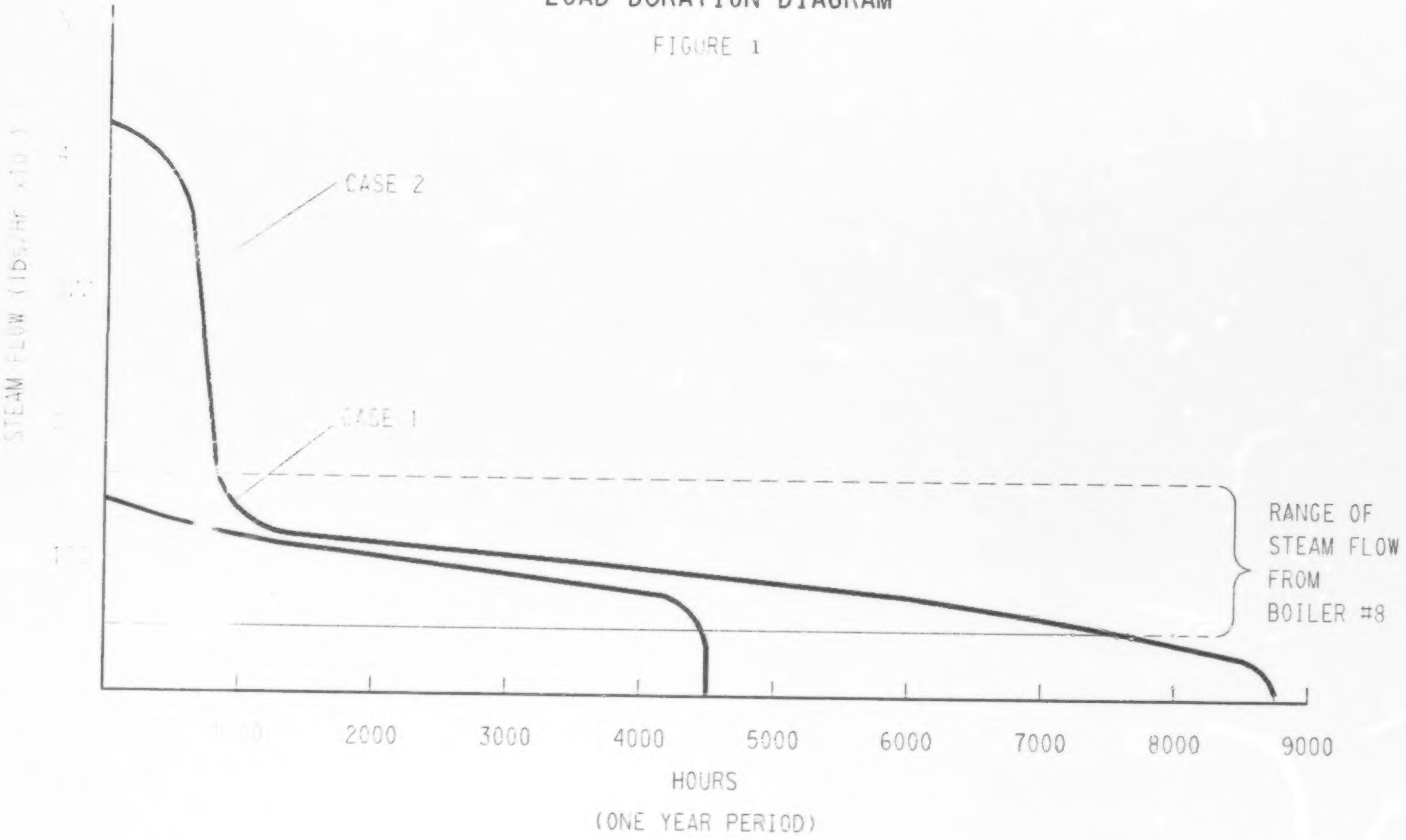
4. RECOMMENDATION

Since the payback period is essentially equal between Option 2 and 4 and the total installed cost of Option 4 is 50% higher than Option 2, Option 2 is recommended. However, during the detailed design stage, the turbine generator performance specification should not preclude the suppliers from offering multistage turbines to ensure competitive bidding has been achieved.

This option consists of a single stage turbine generator set coupled to boiler No. 8 producing 275 psig, dry saturated steam. We also recommend that H.J. Heinz increase the load factor on boiler No. 8 to realize the advantages of a shorter return on the capital investment.

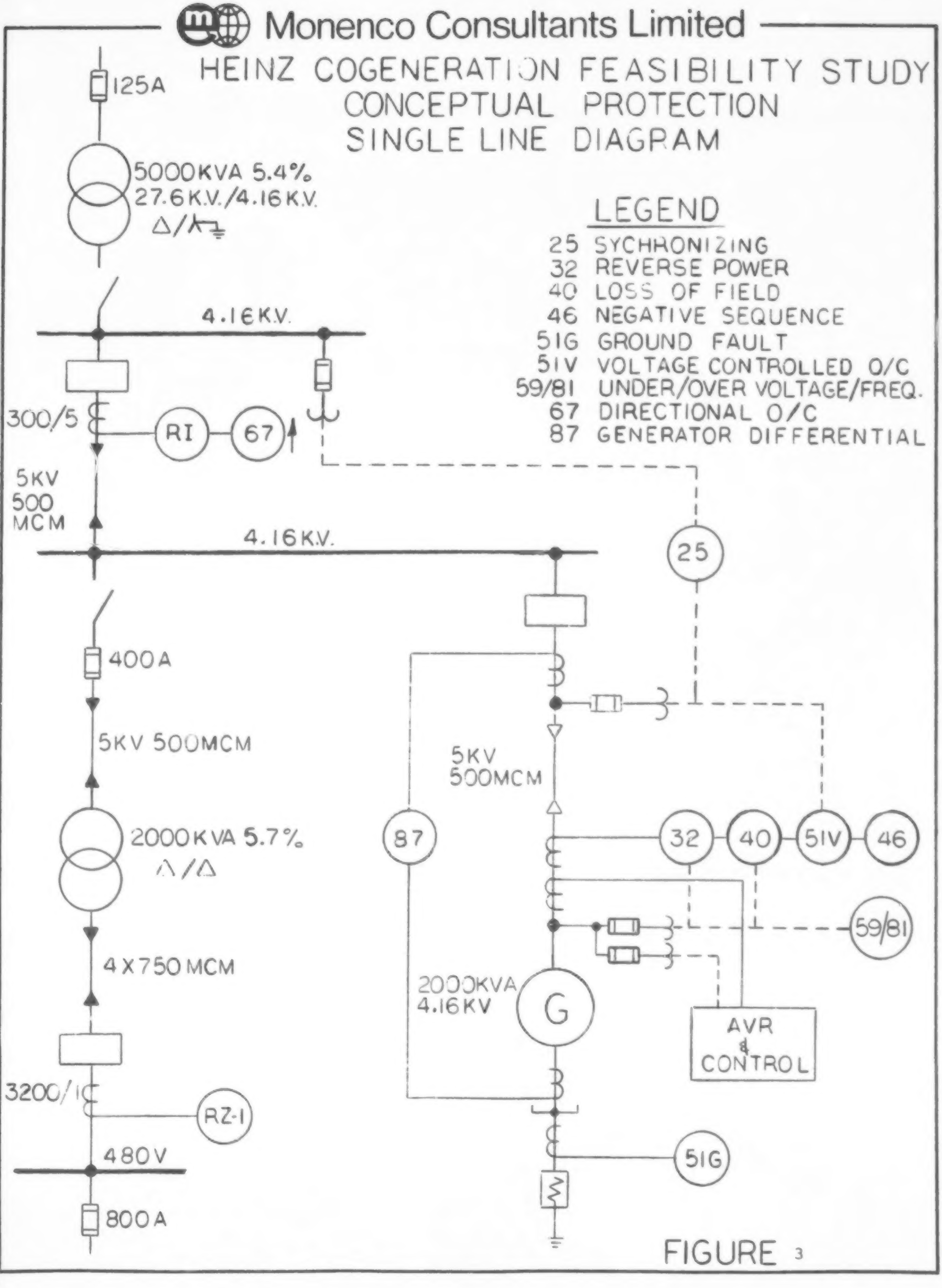
LOAD DURATION DIAGRAM

FIGURE 1



Monenco Consultants Limited

HEINZ COGENERATION FEASIBILITY STUDY
CONCEPTUAL PROTECTION
SINGLE LINE DIAGRAM


125A
5000KVA 5.4%
27.6K.V./4.16K.V.
Δ/⅄
4.16K.V.
300/5
RI
67
5KV
500
MCM
4.16K.V.
25
400A
5KV 500MCM
2000KVA 5.7%
Δ/Δ
4X750 MCM
3200/1
RZ-1
480V
800A
87
5KV
500MCM
32
40
51V
46
59/81
2000KVA
4.16KV
G
AVR
&
CONTROL
51G

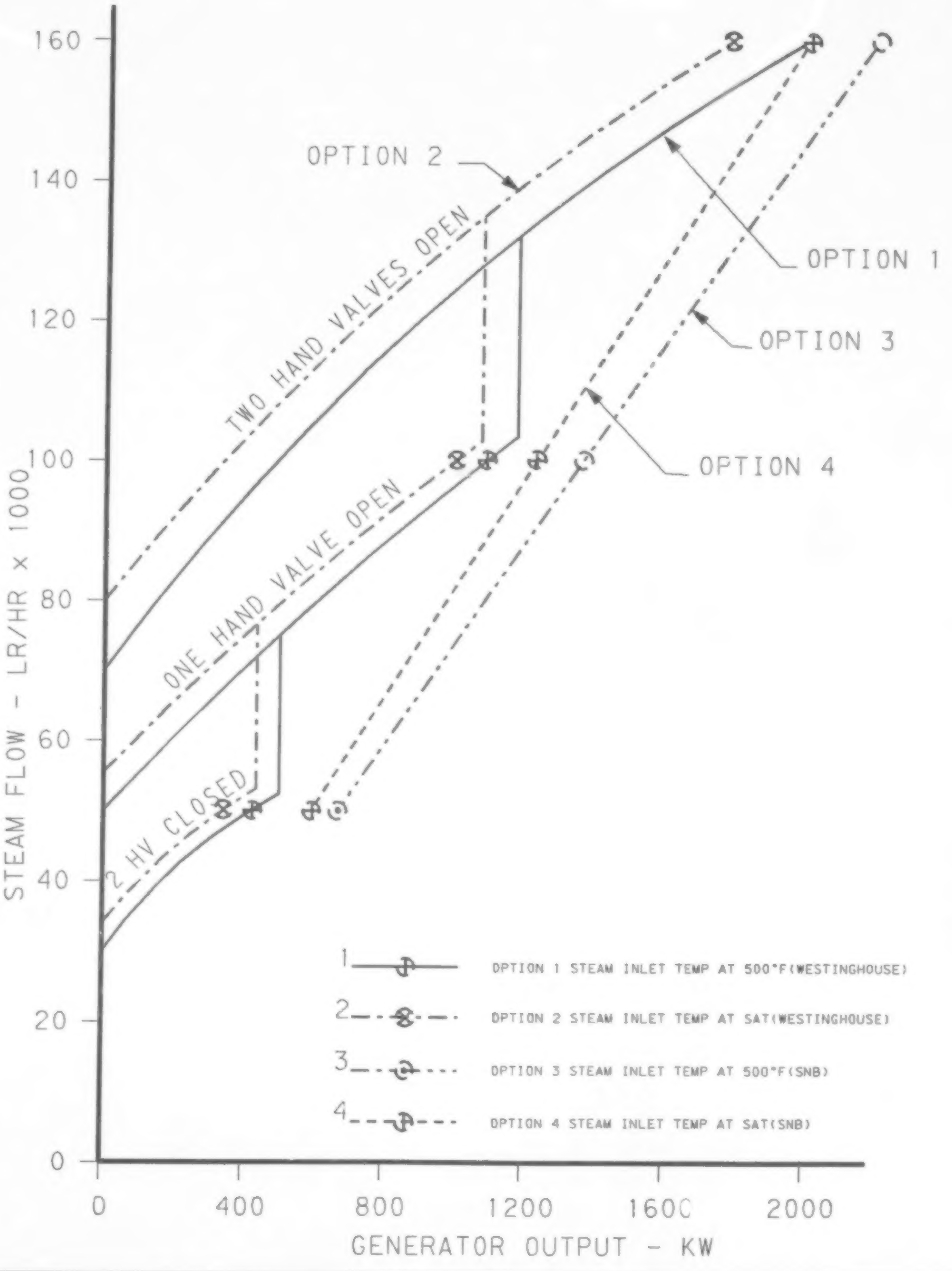
LEGEND

25	SYCHRONIZING
32	REVERSE POWER
40	LOSS OF FIELD
46	NEGATIVE SEQUENCE
51G	GROUND FAULT
51V	VOLTAGE CONTROLLED O/C
59/81	UNDER/OVER VOLTAGE/FREQ.
67	DIRECTIONAL O/C
87	GENERATOR DIFFERENTIAL

FIGURE 3

TURBINE GENERATOR PERFORMANCE CURVES

FIGURE 2



H.J. HEINZ COMPANY OF CANADA LTD.

ANNUAL PROCESS REQUIREMENT

PROCESS STEAM:

Process Steam Used, lb/y	929,300,000
Peak Steam Flow Range, lb/h	150,000 - 425,000
No. of Hours per Year	1,000
Off-peak Steam Flow Range	50,000 - 150,000
No. of Hours per Year	6,600

ELECTRICAL ENERGY:

Peak Demand, kW	4,000
Energy Required, kWh/y	22,000,000

OVERHEAD # 1

H.J. HEINZ COMPANY OF CANADA LTD.

ANNUAL ELECTRICAL GENERATION

	ANNUAL GENERATION kWh	
	CASE 1	CASE 2
OPTION 1 SINGLE STAGE, SHTD	4,300,000	7,500,000
OPTION 2 SINGLE STAGE, SAT	3,900,000 (17.7%)	6,700,000
OPTION 3 MULTISTAGE, SHTD	6,100,000	10,200,000 (46.3%)
OPTION 4 MULTISTAGE, SAT	5,500,000	9,100,000

OVERHEAD # 2

H.J. HEINZ COMPANY OF CANADA LTD.

PROJECT COSTS

	POWER OUTPUT kW	TOTAL INSTALLED COST $	SPECIFIC COSTS $/kW
OPTION 1 SINGLE STAGE, SHTD	1120	1,200,000	1071
OPTION 2 SINGLE STAGE, SAT	960	800,000	833
OPTION 3 MULTISTAGE, SHTD	1800	1,600,000	889
OPTION 4 MULTISTAGE, SAT	1640	1,200,000	732

OVERHEAD # 3

H.J. HEINZ COMPANY OF CANADA LTD.

FIRST YEAR SAVINGS
AND
PAYBACK PERIOD AFTER TAXES

	TOTAL INSTALLED COST $	FIRST YEAR SAVINGS		PAYBACK PERIOD AFTER TAXES	
		CASE 1	CASE 2	CASE 1 YRS	CASE 2 YRS
OPTION 1 SINGLE STAGE, SHTD	1,200,000	79,000	144,000	9.3	6.4
OPTION 2 SINGLE STAGE, SAT	800,000	148,000	252,000	5.0	3.2
OPTION 3 MULTISTAGE, SHTD	1,600,000	154,000	255,000	7.7	5.3
OPTION 4 MULTISTAGE, SAT	1,200,000	212,000	352,000	5.1	3.3

OVERHEAD # 4

Cogeneration Feasibility Study
for
Tage Hansen Greenhouses

By
Guy Couturier, P.Eng.
MacLaren Engineers Inc.

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1.0 INTRODUCTION

The Tage Hansen greenhouse complex located in Leamington, Ontario presently possesses approximately 15 000 m^2 of growing surface area, with a projected expansion of 1500 m^2 in the near future. The operation produces roses and other flowers which are sold in the Ontario, Canadian, and U.S. markets.

With a 1987 annual natural gas consumption of 960 000 m^3 at approximately $140 000, and an annual electrical energy consumption of 3 900 000 kWh at $107 000, this greenhouse complex has been identified as a potential candidate for cogeneration.

MacLaren Engineers Inc. was retained by Tage Hansen in November 1987 to perform a detailed cogeneration feasibility study on the greenhouse complex. Three cogeneration schemes, 150 kW, 300 kW and 400 kW, were developed and analyzed with respect to their technical and economic merits and disadvantages.

2.0 SUMMARY OF RESULTS

In summary, cogeneration is technically feasible at Tage Hansen utilizing equipment readily available on the market. In Figure 1 the details of the 400 kW scheme are schematically depicted. The 400 kW ebullient cooled engine would produce low pressure steam (70 to 90 kPa) which would be used to supplement the existing three boilers. The electrical output of the induction generator, supplemented by the local utility, would service the entire plant. In most instances thermal and electrical load profiles are adequate to implement cogeneration for the months of mid-September to mid-May (refer to Figure 2).

However, the economical rate of return of the schemes developed are marginally attractive. The following table summarizes the rate of return on investment and payback periods associated with three cogeneration schemes developed. The table also shows the effect of varying the capital cost of each scheme.

Sensitivity Analysis on Capital Cost

Power	150 kW		200 kW		400 kW	
Variation	Capital Cost $	ROI (payback)	Capital Cost $	ROI (payback)	Capital Cost $	ROI (payback)
+ 10%	170 000	5.9% (11 y)	328 900	4.9% (12 y)	410 000	5.1% (11 y)
base case	155 000	7.2% (10 y)	299 000	5.9% (11 y)	373 000	6.4% (11 y)
- 20%	124 000	10.5% (9 y)	239 000	9.0% (9 y)	198 000	9.6% (9 y)
- 40%	93 000	15.4% (6 y)	179 000	13.7% (6 y)	224 000	14.1% (6 y)
- 50%	50 000	19.1% (5 y)	150 000	16.9% (5 y)	186 500	17.8% (5 y)

Economic sensitivity analyses were also performed on the following parameters.

a) Fuel Cost and Maintenance

The effect of varying fuel and maintenance costs on payback period and "before tax" rate of return over 15 years is presented below. The analysis is only shown for the 150 kW scheme. The results are similar for the 300 kW and 400 kW scheme.

Sensitivity Analysis on Fuel and Maintenance Costs

ROI (%) and payback (yrs)

Fuel Cost (¢/m^3)	Maintenance Cost (¢/kWh)					
	0.5	0.8	1.0	1.5	1.8	2.0
12.23	15.4% (7 y)	13.2% (8 y)	11.7% (8 y)	7.4% (10 y)	4.6% (12 y)	2.4% (13 y)
12.73	14.9% (7 y)	12.6% (8 y)	11.1% (8 y)	6.8% (10 y)	3.8% (12 y)	1.5% (14 y)
15.75	11.5% (8 y)	9.0% (9 y)	7.3% (10 y)	2.2% (14 y)	- -	1.3% (14 y)

The fuel cost figures are provided by Union Gas.

b) Fraction Available Waste Heat Utilized

The effect of varying the per cent available waste heat utilized on the return on investment is shown in Figure 3 for the 150 kW option.

In this analysis all operating parameters are kept fixed except the per cent waste heat utilized. The return on investment goes from 9% ROI at 100% available waste heat utilized down to 0% ROI at 75% waste heat used. The fraction of available waste heat utilized has a dramatic effect on the economic viability of the schemes.

Figure 3 indicates that the engine should not be run for extended periods of time unless at least 75% of the available waste heat is used.

c) Electricity Cost

To highlight the effect on increased electricity cost, the analysis was performed with the following rates:

Sensitivity Analysis on Electricity Cost

energy charge (¢/kWh)	demand charge (¢/kWh)
4.08	4.8
4.5	5.3
5.0	5.8
5.5	6.3
6.0	6.8
6.5	7.3
7.0	7.8

The resulting payback period for the 150 kW case is shown in Figure 4 for each combination of energy charge and demand.

A decrease on payback from 10 years down to 4 years would result should the electricity cost increase by 70%. This exercise is purely academic at this stage since there is no indication that such a variation in electricity cost would be experienced in the near future.

d) Operating Hours

The thermal and electrical loads of the greenhouse peak in the winter and are at a low in the summer, therefore the electrical and thermal load cycles of the plant were analyzed carefully to determine a reasonable operating schedule for each cogenneration scheme.

The impact of varying the yearly operating hours is shown in the following table.

Sensitivity Analysis on Yearly Operating Hours

ROI (%) and payback (yrs)

Scheme	8760 hrs	5728 hrs	5639 hrs	5360 hrs	4895 hrs
150 kW	9.1% (9 y)(4)	6.8% (10 y)(1)	6.5% (11 y)(2)	-	6.0% (11 y)(3)
300 kW	12.4% (8 y)(1)	-	-	5.4% (11 y)(1)	
400 kW	13.7% (7 y)(4)	-	-	6.0% (11 y)(1)	

(1) base case

(2) shut down during June, July, and August

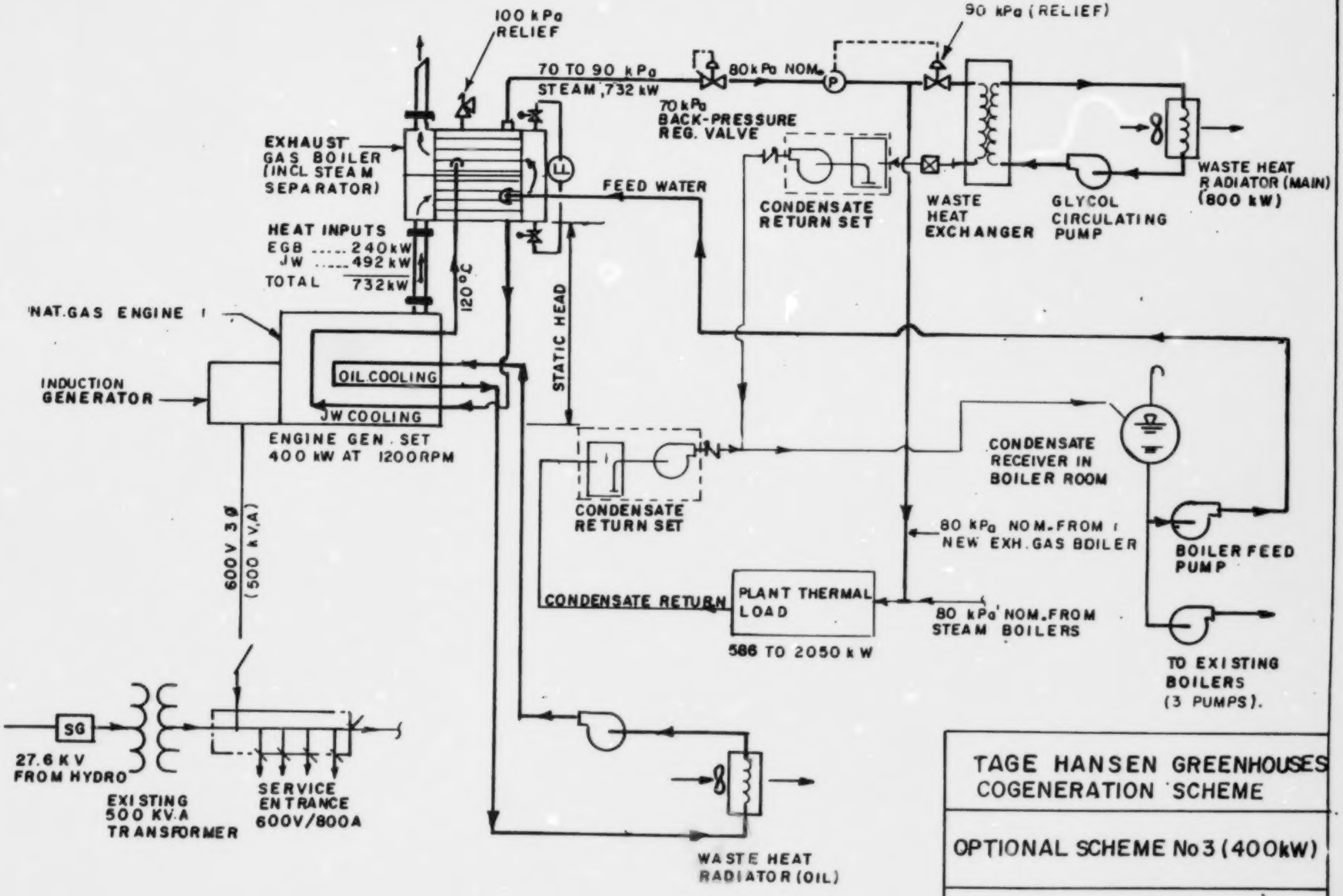
(3) shut down during June, July, August, and May

(4) year -round operation at full rated electrical output

3.0 CONCLUSION

Cogeneration for the greenhouse is viable but economically marginally attractive. Further consideration should be given to the benefit of installing back-up standby power capability. In the event that this is desirable, the return on cogeneration could be re-calculated based on the incremental cost of providing a cogeneration package with standby capability as opposed to purchasing an additional new engine-generator standby set.

The possibility of implementing additional summertime heat loads to increase the operating period - in the form of absorption cooling (for ground cooling), dehumidification (dessicant regeneration), and perhaps others - should be given further consideration to determine their economical and technical benefits.


100 kPa RELIEF
70 TO 90 kPa STEAM, 732 kW
80 kPa NOM.
70 kPa BACK-PRESSURE REG. VALVE
90 kPa (RELIEF)
EXHAUST GAS BOILER (INCL STEAM SEPARATOR)
FEED WATER
CONDENSATE RETURN SET
WASTE HEAT EXCHANGER
GLYCOL CIRCULATING PUMP
WASTE HEAT RADIATOR (MAIN) (800 kW)
HEAT INPUTS
EGB ...... 240 kW
JW ...... 492 kW
TOTAL 732 kW
120°C
NAT. GAS ENGINE
STATIC HEAD
INDUCTION GENERATOR
OIL COOLING
JW COOLING
ENGINE GEN. SET 400 kW AT 1200 RPM
CONDENSATE RECEIVER IN BOILER ROOM
CONDENSATE RETURN SET
600 V 3 Ø (500 kV.A)
80 kPa NOM. FROM NEW EXH. GAS BOILER
BOILER FEED PUMP
CONDENSATE RETURN
PLANT THERMAL LOAD
586 TO 2050 kW
80 kPa NOM. FROM STEAM BOILERS
TO EXISTING BOILERS (3 PUMPS).
SG
27.6 KV FROM HYDRO
EXISTING 500 KV.A TRANSFORMER
SERVICE ENTRANCE 600V/800A
WASTE HEAT RADIATOR (OIL)

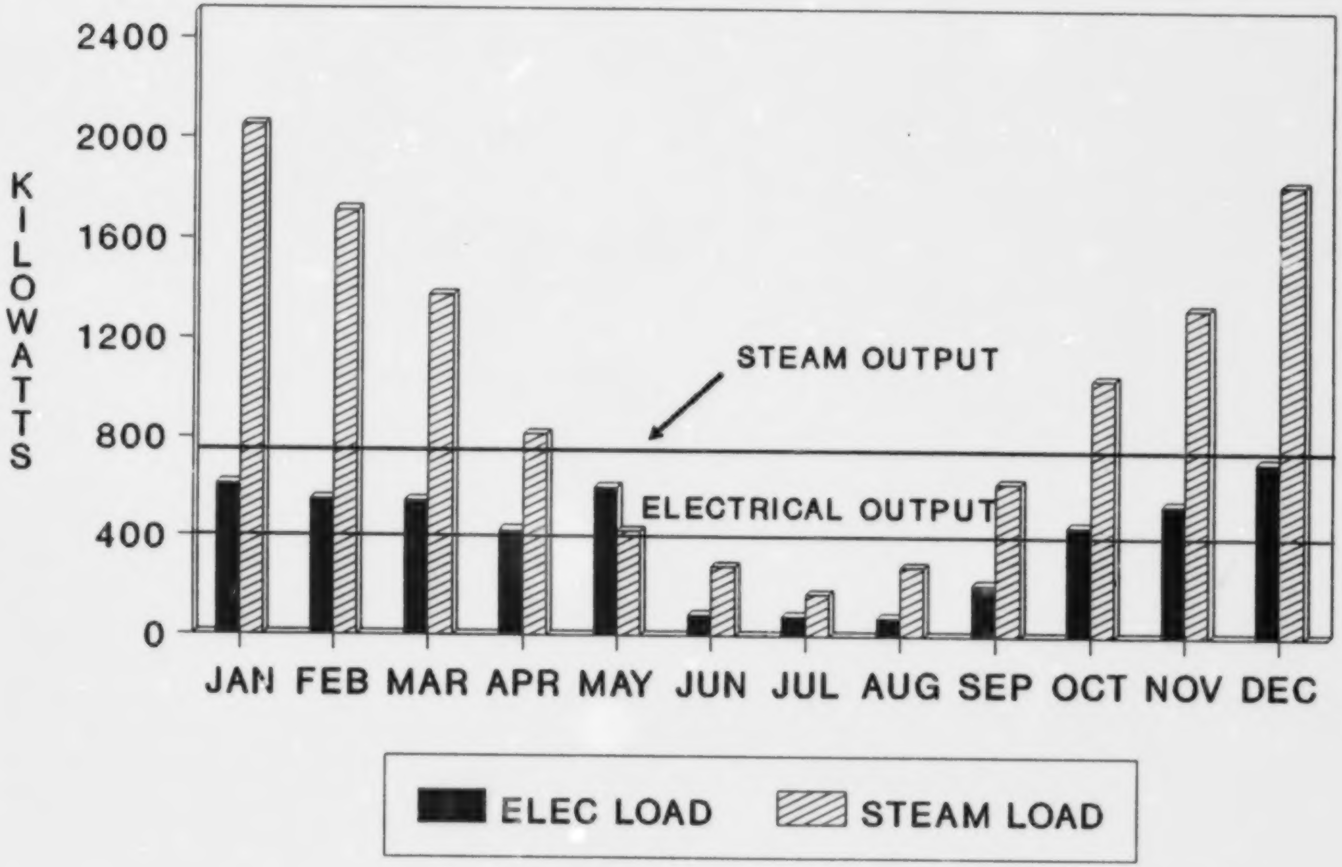
TAGE HANSEN GREENHOUSES
COGENERATION SCHEME

OPTIONAL SCHEME No 3 (400kW)

FIGURE 1

400 KW ENGINE-GENERATOR

PLANT LOADS and COGEN. MODULE OUTPUT



Loads are monthly averages

FIGURE 2

SENSITIVITY ANALYSIS

ROI vs % RECOVERABLE WASTE HEAT USED

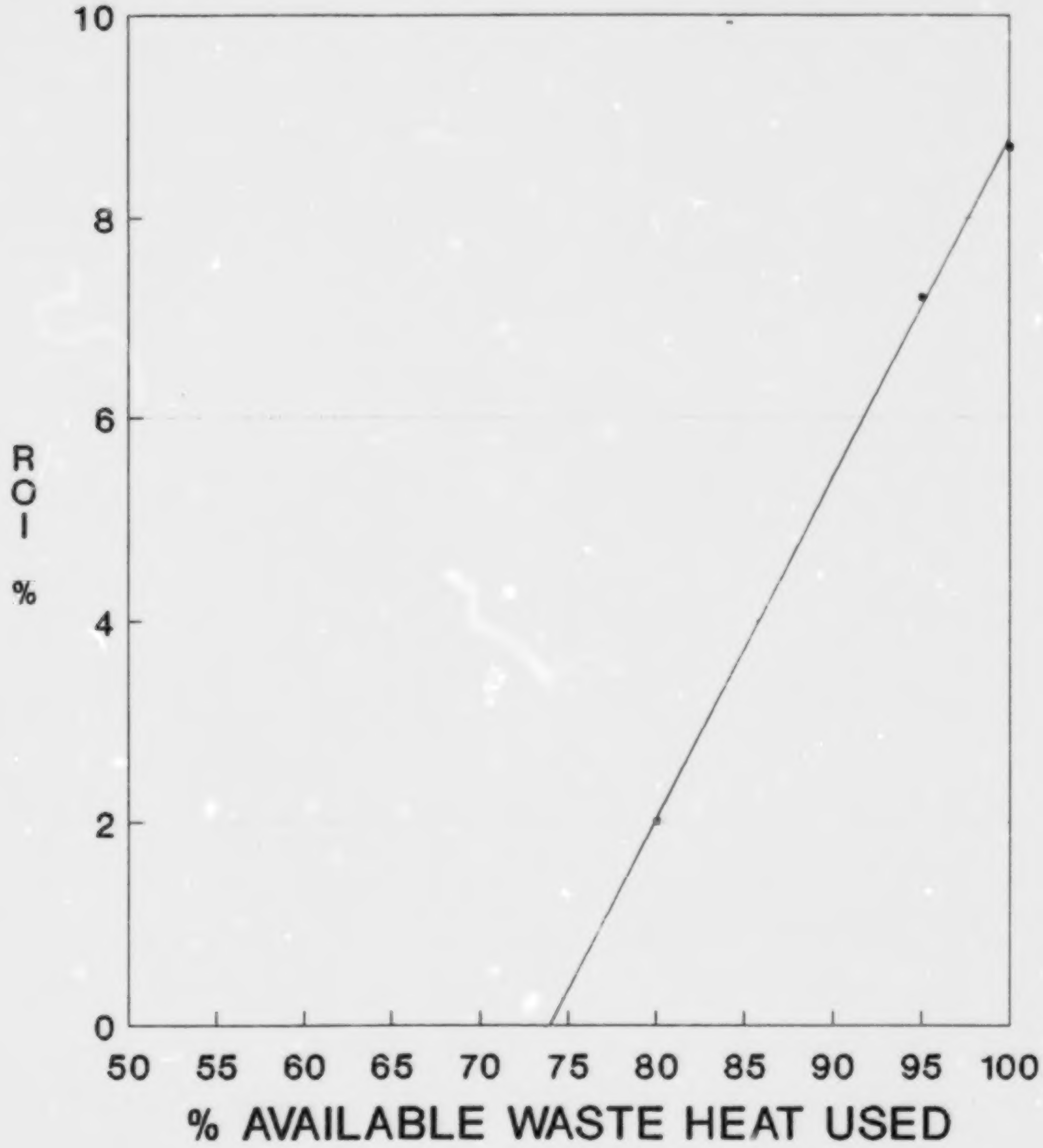


FIGURE 3

SENSITIVITY ANALYSIS

PAYBACK vs ELECTRICITY COST

For 150 kW base case

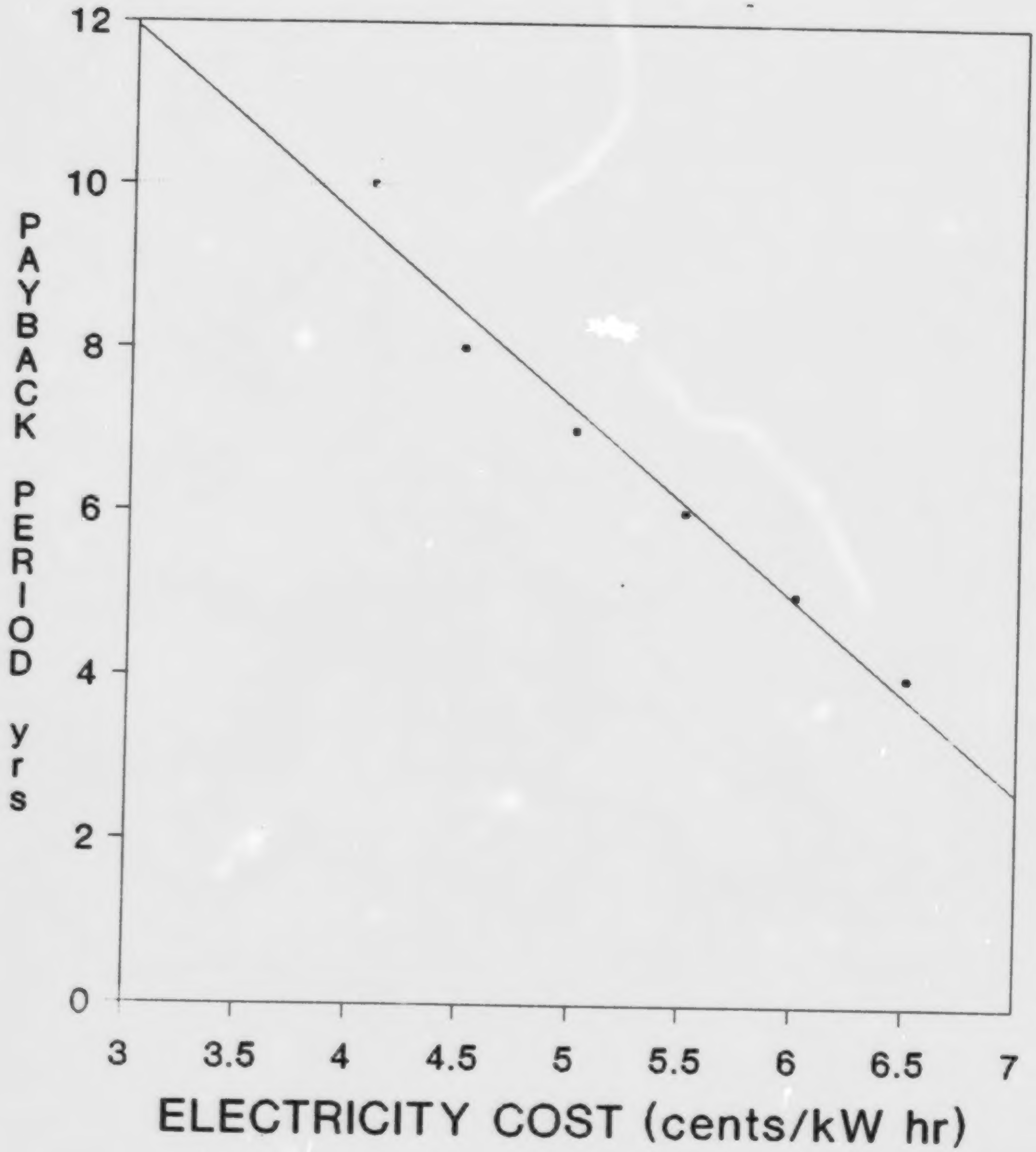


FIGURE 4

Cogeneration Demonstration
Union Gas Limited - Halton Division

By
Martin Lensink
Union Gas Limited

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COGENERATION DEMONSTRATION

UNION GAS LIMITED - HALTON DIVISION

Presented by Martin Lensink, Coordinator, Industrial Gas Applications

The case study that I want to tell you about this afternoon is the cogeneration demonstration system that Union Gas recently installed in one of its own buildings. As a result of this presentation, you will realize that completing a cogeneration project is relatively straightforward.

The format of this presentation is as follows: first, I will introduce you to our Halton Service Center; then explain why cogeneration was considered for this building; describe how the project was coordinated; next, you will see the equipment that was installed. And finally, I will review the expected benefits of this demonstration project.

I will begin by briefly describing Union Gas to you. Union Gas is really three systems in one:

First, we serve over 534,000 industrial, commercial and residential distribution customers in Southwestern Ontario in an area stretching from Windsor in the west to Oakville in the east and from Owen Sound in the north to Lake Erie in the south;

Second, we operate Canada's largest storage facility with a capacity of more than 100 BCF and provide storage services; and

Third, we operate the third largest transmission system in terms of capacity with a peak day capability of more than 2.5 BCF and provide transportation services.

Our Head Office is in Chatham and we have regional offices in Windsor, London, Waterloo and Hamilton. We are a wholly owned subsidiary of Union Enterprises.

Our Halton Service Centre is in Burlington and can be seen from the QEW. Halton is one of our fastest growing divisions, now serving over 66,000 customers. The building is not solely an office building, nor is it a manufacturing plant. Rather, it is a multipurpose building. The 100 employees that work out of this building service and sell gas fired equipment; maintain distribution pipelines and stations; build new distribution mains and services; and accept customer payment. In April 1987, the building was significantly renovated and expanded to its present size of 28,000 square feet.

When design of the renovations began in 1985, cogeneration was considered for four reasons:

1. Union is committed to using natural gas fired equipment wherever practical;
2. The Halton Service Centre requires the availability of standby power. The standby electrical load at Halton is 45 kW. The building did not have a standby gen-set prior to the expansion. We realized that if we needed a standby gen-set anyway, a cogeneration system would be practical. It would provide both standby power and energy savings. Moreover, cogeneration would reduce the under utilization of a capital asset;
3. In anticipation of growing interest in cogeneration, Union decided it would be prudent to demonstrate a small system in one of its buildings;
4. Cogeneration was a good match for the building. It has a high thermal space heating load for part of the year and its electrical power needs exceed 64 kW during operating hours. Based on meeting these requirements, the cogeneration system would yield annual energy savings.

The project progressed through a series of logical steps. First, a comprehensive feasibility study was completed by one of my Union Gas colleagues. The study concluded cogeneration was in order. Three alternatives for heating, cooling and cogenerating at the Halton Service Centre were then thoroughly investigated based on design requirements for 80 tons of cooling, 1,000,000 Btu per hour of heating and 335 kW of electricity. One alternative was a skid mounted package that included a double effect 40 ton absorption chiller. However, this package, developed by the Gas Research Institute, was still under field test and not commercially available at the time. The design which was chosen is shown in schematic form on the slide above. Note the cogeneration system provides hot water to the heating system by way of a heat exchanger and it supplies electricity to the building in parallel with the local utility.

We then asked ourselves, do we:

1. Do the engineering, construction and commissioning ourselves?
2. Contract with a cogeneration supplier that provides advice and "design build" services?
3. Retain a consulting engineer that would do only the cogeneration on a turn-key basis; or?
4. Retain both the building mechanical and electrical consulting engineers?

We decided to retain the two consulting engineers already selected for the building project. Consulting engineers are familiar with managing projects to strict time schedules and budget constraints. We assigned one of our people to provide criteria to the consultants and coordinate the project. The consultants reported to our coordinator and managed the project on our behalf.

The project proceeded in an orderly fashion as follows:

July 1986	Tender was sent out.
October 1986	Cogeneration hardware was ordered.
April 1987	Electrical drawings were forwarded to the utilities.
June 1987	Cogeneration unit shipped to site.
January 1987	Electrical controls approved.

Now I will show you the equipment that was actually installed.
- the natural gas entering the engine at 7" w.c. via the 2" diameter gas train.
- the 12 volt DC battery starter.
- the natural gas fired reciprocating engine - 6 cylinder inline - 330 cubic inch displacement.
- the exhaust noise silencer and heat exchanger, through which the jacket water gains temperature.
- the synchronous generator rated at 65 kW at 1800 rpm can supply electricity in the event of an interruption.
- the main jacket water heat exchanger which supplies hot water to the perimeter baseboard hydronic heating system. The heat transfer medium is 50% glycol, 50% water. When the building cannot utilize all the heat from the engine, the amount of heat is automatically reduced.
- the adjustment is made inside this cabinet by a process controller that relates return water temperature to engine electrical load.
- and finally, the power output from the generator.

Now, I want to review with you how we expect to operate this system and the benefits that we have derived from this installation.

1. With respect to maintenance, we will do the routine maintenance ourselves such as oil changes, spark plug and filter changes. We are considering a service contract for minor and major overhauls. We will gain valuable experience in cogeneration maintenance practices and calculation of life cycle maintenance costs.

2. We will run the system as much as possible to maximize the economic returns. On the basis of the incremental cost of the cogeneration equipment of $36,000 and 3000 hours per year of operation, we will realize annual savings of $4,000. Based on 5000 hours per year of operation, annual savings of $9,000 would be realized. Cogeneration is certainly a viable energy management option. However, when used as a standby power source, cogeneration shows especially good economic results.

3. We have learned that the choice of project manager is not a decision that should be taken lightly. On this project, our electrical consultant and a mechanical consultant were both involved with the cogeneration system and performed their usual function in a competent manner. For some cogeneration projects, it might be better to hire a consulting specialist for just the cogeneration hardware - someone who

understands the dynamic relationships between mechanical and electrical components and can provide cogeneration design, installation supervision, and project management on a turn-key basis.

4. The fact that Union supports the concept of cogeneration through implementation in one of its own buildings shows our confidence in this technology.

5. The site is conveniently located making it readily accessible for viewing by interested customers.

6. Installation and operating information based on our actual experience will be passed on to Union sales representatives in training sessions in order to prepare them for cogeneration discussions with customers.

7. The insights from the project have improved Union's ability to help customers develop specifications for their systems needs, and in the process avoid potential operational problems.

This project involves one type of cogeneration technology, namely reciprocating engines in a specific application. Union is actively pursuing other cogeneration and parallel generation projects in cooperation with the Ministry of Energy and Ontario Hydro as well as to raise public awareness of this gas utilization concept. Union believes it has a responsibility to support the province in its goals of improving the efficiency of our energy use and diversifying our sources of energy supply.

Thank you for your attention.

SUGGESTED INTRODUCTION OF MARTIN LENSINK

- The next case study is on Union Gas' Halton Cogeneration Demonstration Project.
- It will be presented by Martin Lensink, Co-Ordinator, Industrial Gas Applications.
- Martin has been with Union Gas for 6 years; 2 years in Facilities Planning; 2 years in Marketing; and the last 2 years in Industrial Gas Sales.
- In his present role, he provides technical and marketing support for several new industrial gas technologies and applications, including cogeneration.
- Prior to Union Gas, Martin designed and sold oil hydraulic power units.
- Martin is a 1980 graduate of McMaster University in Hamilton with a degree in Mechanical Engineering and Management.

Interconnection and Rates

By
A. G. Barnstaple, P.Eng.
Ontario Hydro

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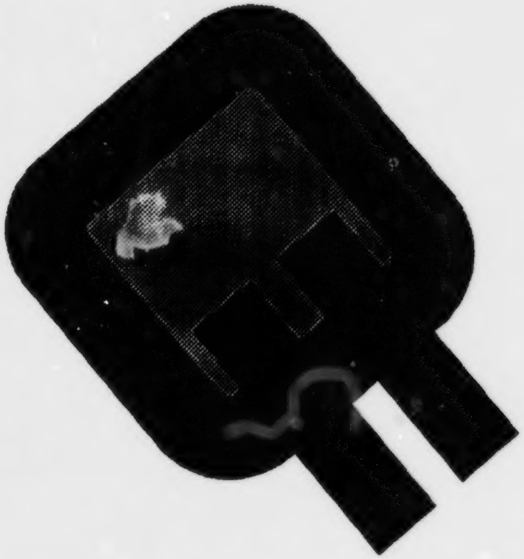
PG

Parallel Generation



Parallel Generation

Electrical generation not owned by Ontario Hydro but interconnected to the bulk electricity or distribution systems.

CoG
#4

Parallel Generation

Cogeneration

Co-production of power and heat from the same fuel source, usually at high efficiency

Pa 5

Parallel Generation

Reasons For Ontario Hydro´s Interest

- Consistent with government policy
- Possible planning & operating benefits to power system
- Possible lower capital & long run costs
- Improvement in overall energy efficiency & resource utilization
- High public acceptance

Present Policy Provides For:

- Purchasing of power
- Wheeling of power
- Technical assistance on cost recovery basis

Parallel
Generation

Guidelines For Purchases

- Generator located in power district or municipal utilities
- Net power from generation site
- Host municipal utilities have first rights to purchase
- Approved rates & standard service conditions
- Costs of connection (except metering) charged to generator

Parallel Generation

Parallel Generation Programs

Program A: Projects up to 5 MW

- Standard rates & contracts
- Delivered mainly by Regions/assist by Marketing

Program B: Projects over 5 MW

- Rates up to avoided cost of project
- Negotiated contracts
- Delivered by Marketing/assist by Regions
- Competitive proposals possible
- Capital incentives possible

Parallel Generation

Purchase Rates (1988)

OPTION	ABOVE 65% M.C.F. ¢ /kWh	BELOW 65% M.C.F. ¢ /kWh	COMMENTS
Standard	3.76 + CPI	2.54	Revised annually by Ontario Hydro
Fixed	4.94 (Fixed)	2.54 (Annually revised)	Fixed rate for 10 Yrs New projects based on renewable energy resources
Time of Supply	Varies on time of purchase	Varies on time of purchase	Time of purchase rates for capacity 250kW or greater
Occasional Supply	3.76 x M.C.F.	3.76 x M.C.F.	Occasional purchase from direct customers

Parallel Generation

Corporate Planning - Parallel Generation

Inservice end of 1987	26 MW
Committed additions to end of 1989	102 MW
Expected inservice to end of 1993	600 MW
Expected inservice to end of 2000	1000 MW

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Parallel Generation

Parallel Generation Program Development

- Corporate Business Plan, 1000 MW by year 2000
- New back-up power policy for customer generation
- Proposal process for larger projects (›5 MW)
- Financial incentives for load-displacement generation
- Transmission system incorporation plans
- Lease-purchase arrangements for hydraulic projects
- Hosting of PG on Hydro-controlled sites

**Parallel
Generation**

Proposed Guidelines For Cogeneration Financing Assistance

- Available only to technically & financially qualified projects
- Low interest loans appear most workable & affordable
  - Loan amount set to meet reasonable financial hurtle (say 3 to 4 year payback)
  - Repayment begins after customer payback (year 4 or 5)
  - Repayment schedule negotiated to suit project & hydro affordability

**Parallel
Generation**

Challenges To Further Development

- Retention of Class 34, or equivalent
- Cogeneration financial incentives
- Equitable power purchase rates & contract conditions
- Natural gas supply & prices
- Environmental acceptance

**Parallel
Generation**

Cogeneration Project Economics vs Class 34 & Low Interest Loan

	EQUIV. IRR %	ROE %
W/O Loan, W/O Class 34	5.6	5.6
W/O Loan, W Class 34	9.2	9.2
W Loan, W/O Class 34	7.8	9.0
W Loan, W Class 34	12.8	21.4

Based On: 75 MW Project, $65 Million Capital
6000 BTU/kWh, $2.50/MCF

Natural Gas Supply for Cogenerators

EXPECTATIONS UNDER DEREGULATION

- Direct Purchase Contracts for Large Projects
- Willingness of Producers to Offer Long Term Contracts
- Competitive Pricing & Price Indexing in Near Term

UNCERTAINTIES

- Ability of Unregulated Industry to Meet Long Term Supply Commitments
- Effect of Free-Trade on Long Term Domestic Pricing
- Future Taxes & Royalties

Gas Pricing for Cogeneration Projects

By
Juri Otsason, P.Eng.
Consumers' Gas Company

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GAS PRICING FOR COGENERATION PROJECTS

GOOD AFTERNOON LADIES AND GENTLEMEN. I HAVE BEEN ASKED TO TALK TODAY ABOUT GAS PRICING AS IT RELATES TO COGENERATION PROJECTS. IN FACT, RECENT TRENDS IN GAS PRICING AND PARTICULARLY ITS RELATIONSHIP TO ELECTRICITY PRICES IS THE PRIMARY REASON WHY THERE IS NOW A SIGNIFICANT LEVEL OF INTEREST IN COGENERATION AS IS EVIDENCED BY THE LARGE TURNOUT WE HAVE HERE TODAY.

THIS GRAPH SHOWS THE RELATIONSHIP BETWEEN THE CONSUMERS GAS RATES AND ELECTRICITY RATES OVER THE PERIOD FROM 1982 TO 1988. THE ELECTRIC TO GAS PRICE RATIO HAS INCREASED FROM APPROXIMATELY 2.3 TO 4.3 OVER THIS PERIOD, THEREBY DRAMATICALLY IMPROVING THE ECONOMIC VIABILITY OF GAS FIRED COGENERATION.

THE SIGNIFICANT DECLINE IN GAS PRICES SINCE 1986 IS THE RESULT OF THE DEREGULATION OF GAS PRICES TOGETHER WITH AN AMPLE SUPPLY OF GAS IN WESTERN CANADA. IN FACT, THIS GRAPH DOES NOT FULLY REFLECT THE DECLINE IN PRICES WHICH HAS OCCURRED SINCE 1986. UNDER THE RULES OF DEREGULATION, THE UTILITIES HAVE NOT BEEN ABLE TO FULLY ACCESS THE NOW DEREGULATED GAS MARKET DUE TO EXISTING LONG-TERM GAS SUPPLY CONTRACTS WITH TRANSCANADA PIPELINES. THEREFORE, THE DECLINE IN THE SALES RATES OF THE UTILITIES HAVE NOT KEPT PACE WITH THE PRICE REDUCTIONS WHICH ARE AVAILABLE TO END USERS WHO, IN THE NEW ENVIRONMENT, CAN PURCHASE THEIR GAS DIRECTLY FROM GAS PRODUCERS OR BROKERS.

AS A MATTER OF FACT, I AM NOT SURE THAT I OR ANY GAS UTILITY REPRESENTATIVE IS THE BEST PERSON TO TALK ABOUT GAS PRICES IN TODAY'S ENVIRONMENT. TODAY, A SIGNIFICANT PORTION OF THE GAS BEING USED BY MAJOR GAS USERS IS NOT SOLD BY THE UTILITY, BUT INSTEAD PURCHASED BY THE END USER DIRECTLY FROM PRODUCERS OR BROKERS. AS A RESULT, WE AT THE UTILITY USUALLY DO NOT KNOW THE PRICE OR OTHER TERMS OF THE GAS SALES TRANSACTIONS, AND MY COMMENTS TODAY WILL IN PART BE BASED ON DISCUSSIONS I HAVE HAD OVER THE PAST COUPLE OF MONTHS WITH A NUMBER OF GAS PRODUCERS AND BROKERS.

IN DISCUSSING GAS PRICES, I BELIEVE WE SHOULD FIRST LOOK AT THE COMPONENTS WHICH MAKE UP THE PRICE OF GAS DELIVERED TO THE PLANT SITE. THE DELIVERED PRICE OF GAS CAN BE VIEWED AS MADE UP OF THREE SEPARATE MAJOR COMPONENTS:

1. THE PRICE OF THE COMMODITY.
2. TRANSPORTATION FROM THE PROVINCE OF SUPPLY TO ONTARIO THROUGH THE TCPL SYSTEM.
3. TRANSPORTATION BY THE UTILITY FROM THE TCPL PIPELINE TO THE PLANT.

THE PRICE OF THE COMMODITY IN THIS BREAKOUT WOULD INCLUDE GATHERING WITHIN THE PROVINCE OF SUPPLY AND REPRESENTS THE PRICE AT THE INLET TO THE TCPL SYSTEM, WHICH USUALLY IS AT THE ALBERTA/SASKATCHEWAN BORDER. THE TRANSPORTATION BY THE UTILITY WOULD ALSO, IN ADDITION TO STRAIGHT TRANSPORTATION, TYPICALLY

INCLUDE LOAD BALANCING OR STORAGE SERVICES TO ACCOMMODATE VARIATIONS IN THE DAILY GAS REQUIREMENT AT THE PLANT.

THE FOLLOWING WILL GIVE YOU AN INDICATION OF THE RELATIVE MAGNITUDE OF THE SEPARATE COMPONENTS FOR A SHORT-TERM, THAT IS ONE TO TWO YEAR, DIRECT PURCHASE ARRANGEMENT INTO CONSUMERS' SYSTEM.

COMMODITY AT ALBERTA BORDER	$1.30 - $1.60/GJ
TCPL AT 100% LOAD FACTOR	$0.98/GJ
CONSUMERS	$0.15 - $0.70/GJ
DELIVERED PRICE	$2.43 - $3.28/GJ

OF THE THREE COMPONENTS MAKING UP THE DELIVERED PRICE, THE TCPL AND UTILITY (CONSUMERS) COMPONENTS ARE, AND WILL REMAIN REGULATED. BOTH TCPL'S AND THE UTILITY'S RATES ARE COST OF SERVICE BASED, AND I EXPECT THESE TO INCREASE AT APPROXIMATELY THE RATE OF INFLATION OVER THE LONGER TERM ALTHOUGH THERE WILL BE VARIATIONS FROM THIS IN ANY GIVEN YEAR.

ON THE OTHER HAND, THE COMMODITY COMPONENT IS NOW DEREGULATED AND WILL BE GOVERNED BY THE SUPPLY/DEMAND RELATIONSHIP AND THE SELLER'S EXPECTATIONS ABOUT FUTURE CHANGES IN THIS RELATIONSHIP.

SINCE THERE CURRENTLY IS A SIGNIFICANT GAS SUPPLY SURPLUS IN WESTERN CANADA, MOST SELLERS OF GAS WHO I HAVE TALKED TO ARE VERY

INTERESTED IN SUPPLYING GAS FOR NEW LOADS SUCH AS COGENERATION FACILITIES. THERE ARE SIGNIFICANT DIFFERENCES BETWEEN SELLERS IN TERMS OF THE TYPE AND TERM OF GAS SUPPLY CONTRACT WHICH THEY WOULD BE PREPARED TO OFFER. HOWEVER, MOST ARRANGEMENTS FALL INTO ONE OF THE FOLLOWING THREE CATEGORIES:

1. FIXED PRICE FOR A SPECIFIED TERM

   THESE USUALLY WOULD BE FOR A SHORT-TERM, I.E. ONE TO TWO YEARS, WITH CURRENT ALBERTA BORDER PRICES RANGING FROM $1.30 - $1.60/GJ. SOME SELLERS ARE PREPARED TO OFFER A FIXED PRICE FOR TERMS OF UP TO FIVE YEARS, BUT AT A PREMIUM OF AT LEAST 10% - 15% OVER THE SHORT-TERM PRICE.

2. PRE-DETERMINED PRICE ESCALATION OVER THE TERM

   THESE ARRANGEMENTS ARE AVAILABLE FROM A NUMBER OF SUPPLIERS FOR TERMS OF UP TO FIVE YEARS. USUALLY, THE FIRST YEAR PRICE IS EQUAL TO OR SLIGHTLY HIGHER THAN THE ONE YEAR PRICE, WITH ANNUAL ESCALATION RATES USUALLY IN THE .5¢ - .10¢/GJ RANGE.

3. LONG-TERM CONTRACTS WITH INDEXED PRICE

   THIS APPROACH IS THE MOST COMMON FOR FIRM LONG-TERM GAS SUPPLY ARRANGEMENTS. THERE ARE A LARGE NUMBER OF POSSIBLE

INDICES, AND I WILL TOUCH ON THOSE IN A MINUTE. MOST LONG-TERM, INDEXED CONTRACTS WILL HAVE A FIRST YEAR PRICE WHICH IS 10% - 20% HIGHER THAN THE PRICE FOR ONE YEAR CONTRACT WITH THE MAGNITUDE OF THE PREMIUM DEPENDING ON THE TYPE OF INDEX AND THE TERM OF THE CONTRACT.

WITH RESPECT TO INDEXING FACTORS, THERE ARE A LARGE NUMBER OF POSSIBILITIES AND AGAIN, THERE ARE SIGNIFICANT DIFFERENCES BETWEEN SELLERS AS TO THEIR PREFERENCES. THE FOLLOWING ARE SOME OF THE COMMONLY SUGGESTED FACTORS:

1. THE CPI

THIS IS NOT VERY POPULAR AND AS A STANDALONE INDEX, WOULD LIKELY REQUIRE A SIGNIFICANT STARTING POINT PRICE PREMIUM.

2. ONTARIO HYDRO BUY BACK RATE

ALTHOUGH SOME SELLERS ARE PREPARED TO INDEX TO THIS FACTOR, IT IS NOT VERY POPULAR SINCE THERE IS A PERCEPTION THAT THERE IS NO WELL DEFINED BASIS FOR HOW THIS RATE IS ESTABLISHED.

3. ONTARIO HYDRO BULK POWER OR INDUSTRIAL ELECTRICITY RATES

THERE ARE VERY MIXED VIEWS ON THIS INDEXING FACTOR. SOME SELLERS BELIEVE THIS IS A GOOD INDEX FROM THEIR VIEWPOINT, SINCE THEY EXPECT THAT THE ELECTRICITY RATES WILL ESCALATE FASTER THAN GAS PRICES. OTHERS ARE CONCERNED ABOUT POSSIBLE POLITICAL INFLUENCES ARTIFICIALLY DEPRESSING ELECTRICITY RATES.

4. OIL PRICES

THIS IS NOT VERY POPULAR AS A STANDALONE INDEX, DUE TO THE VOLATILITY OF WORLD CRUDE OIL PRICES. HOWEVER, MANY SELLERS WOULD INCLUDE THIS IN A MULTI FACTOR INDEX.

5. GAS PRICES

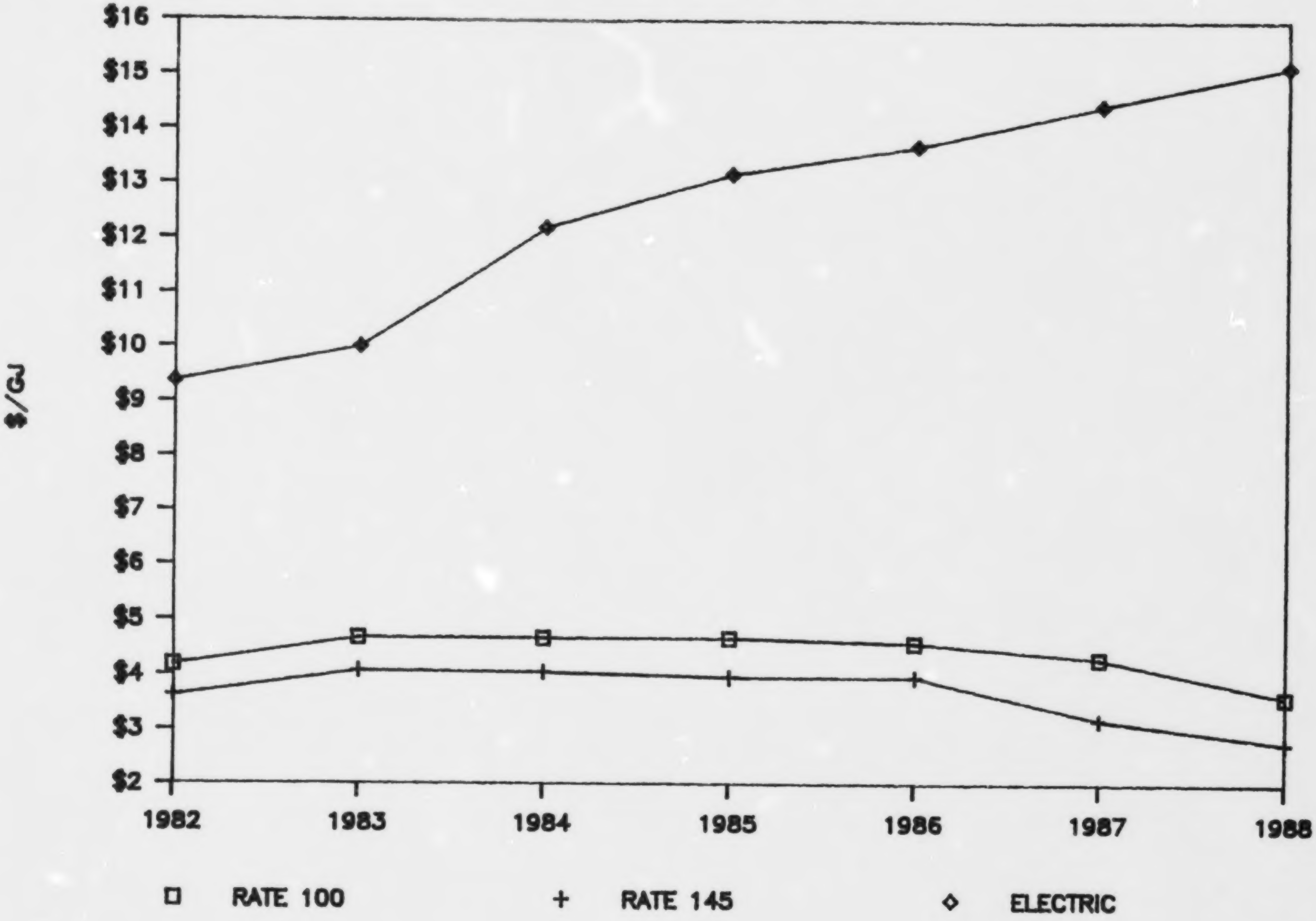
MANY SELLERS WOULD BE INTERESTED IN INDEXING TO SOME FORM OF GAS PRICE; HOWEVER, THERE ARE SOME CONCERNS ABOUT HOW TO DEFINE THE PRICE TO BE USED FOR THE INDEX.

MOST SELLERS WOULD PREFER A COMBINATION OF MULTIPLE INDEXING FACTORS, SINCE IT REDUCES THE POSSIBILITY OF EXTREMES DUE TO SWINGS IN THE PRICE OF A SINGLE COMMODITY. FROM A COGENERATOR'S VIEWPOINT, THE USE OF A PROPERLY WEIGHTED MIX OF ELECTRICITY AND GAS PRICES WOULD BE AN IDEAL INDEX, SINCE IT COULD PROVIDE AN ASSURED RETURN OR SAVINGS FOR A GAS FIRED COGENERATION PROJECT, AND THIS IS ALSO A COMBINATION WHICH APPEALS TO MANY SELLERS.

IN SUMMARY, THERE ARE A LARGE NUMBER OF WILLING SELLERS IN THE NEW DEREGULATED GAS MARKETPLACE, AND OBTAINING A GAS SUPPLY FOR YOUR CO-GENERATION PROJECT AT REASONABLE PRICES SHOULD NOT BE A BARRIER.

IN EVALUATING YOUR GAS PURCHASE OPTIONS, YOU SHOULD TALK TO MANY SUPPLIERS AND FEEL FREE TO BE CREATIVE IN SUGGESTING THE TYPE OF PRICING ARRANGEMENT WHICH SUITS YOUR REQUIREMENTS.

ENERGY PRICE COMPARISON 1982 — 1988



COMMODITY AT ALBERTA BORDER	\$1.30 – \$1.60/GJ
TCPL AT 100% LOAD FACTOR	\$0.98/GJ
CONSUMERS	\$0.15 – \$0.70/GJ
DELIVERED PRICE	**\$2.43 – \$3.28/GJ**

Gas Sales Contract

By
Bob Adie
Union Gas Limited

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SLIDE 1 (PICTURE OF A TYPCIAL GAS SALES CONTRACT)

OPENING COMMENTS

AS THE LAST SPEAKER OF THE DAY, I'LL ATTEMPT TO BE BRIEF, NOT BECAUSE I THINK YOU NEED A DRINK, BUT OUT OF CONSIDERATION FOR THE ONTARIO BREWING AND DISTILLING INDUSTRY THAT USE NATURAL GAS IN THE PRODUCTION OF THOSE WONDERFUL PRODUCTS.

AT FIRST GLANCE, CONTRACTS ARE MYSTIFYING AND UNNECESSARILY COMPLEX. THEY TRANSFORM YOU AND I TO PARTIES OF THE 1ST AND 2ND PART WHILE THE REST OF THE WORLD IS RELEGATED TO 3RD PARTIES WHOM WE PRAY WILL NEVER BE INVOLVED.

CONTRACTS HAVE THE ABILITY, HOWEVER, TO ACCURATELY DEFINE THE RESPONSIBILITIES OF THE CONTRACTING PARTIES. THEY ALLOW YOU TO PROVIDE WAYS OF RESOLVING CONFLICTS AND DEALING WITH UNFORESEEN EVENTS IN A BUSINESS LIKE MANNER TO A FAIR AND EQUITABLE SOLUTION. MORE IMPORTANTLY WHEN UNDERTAKING A PROJECT LIKE COGENERATION, CONTRACTS CAN PROVIDE SECURITY AND ENSURE, TO A SIGNIFICANT DEGREE, THE ECONOMIC SUCCESS OF THE VENTURE.

TODAY, WITH THE LIMITED TIME AVAILABLE, I WOULD LIKE TO REVIEW WITH YOU PURCHASE-TRANSPORTATION AND SALES CONTRACTS. I DON'T HAVE THE COURAGE OR TIME TO STAND HERE AND READ THEM TO YOU BUT ALLOW ME TO HIGHLIGHT WHAT I CONSIDER TO BE THE IMPORTANT ASPECTS OF EACH.

SLIDE 2

THE NEW ENVIRONMENT WHICH ENCOURAGES MARKET SENSITIVE GAS PRICING THROUGH DIRECT PURCHASE OF GAS BETWEEN THE PRODUCERS OF GAS AND THE END USE CUSTOMER REQUIRES MORE CONTRACTING THAN HAS BEEN THE CASE HISTORICALLY. YOU MAY NOW FIND YOURSELF CONTRACTING FOR GAS IN ALBERTA OR SASKATCHEWAN DIRECTLY WITH EITHER A PRODUCER OR BROKER. THIS MAY THEN REQUIRE A TRANSPORTATION CONTRACT WITH TCPL TO MOVE THE GAS FROM THE SASKATCHEWAN/ALBERTA BORDER THROUGH TO ONTARIO AND YET ANOTHER AGREEMENT WITH THE LOCAL DISTRIBUTION COMPANY (LDC) TO YOUR PLANT GATE. IF YOU ELECT TO PARALLEL GENERATE ELECTRICITY OR PURCHASE STANDBY POWER SERVICE, YET ANOTHER CONTRACT FOR THE SALE OR PURCHASE OF THIS POWER WILL BE REQUIRED WITH ONTARIO HYDRO.

SLIDE 3

ANOTHER METHOD OF CONTRACTING IS THE **BUY/SELL** WHICH INVOLVES THE END USE CUSTOMER PURCHASING GAS (UNDER CONTRACT) IN ALBERTA OR SASKATCHEWAN AND EITHER SELLING THE GAS AT THE BORDER TO THE LDC (AS IN CONSUMER'S GAS CASE) AND THEN CONTRACTING FOR THE REPURCHASE OF THE GAS UNDER THE NORMAL SALES RATE THUS AVOIDING THE CONTRACTING WITH TCPL, OR IN THE CASE OF UNION FOR EXAMPLE, YOU WOULD REQUIRE A TCPL CONTRACT TO TRANSPORT THE GAS TO ONTARIO AND WE WOULD PURCHASE IT FROM YOU AT THAT POINT AND RESELL IT UNDER OUR NORMAL CONTRACT SALES AGREEMENT.

IN EITHER CASE, YOU CAN SEE THAT "CONTRACTING" IS NECESSARY TO ENSURE THE MOST COMPETITIVE GAS PRICE AT POINT OF USE.

I WILL NOW DISCUSS IN GREATER DETAIL THE COMPONENTS OF THE AGREEMENTS THAT WILL BE OF INTEREST TO YOU WHEN CONTRACTING FOR THE SUPPLY AND TRANSPORTATION OF GAS.

SLIDE 4

I WILL SPEND MORE TIME DISCUSSING THE **PRODUCER CONTRACTS** SIMPLY BECAUSE I HAVE ELECTED TO PROGRESS FROM WEST TO EAST. THE CONTRACTS WITH TCPL AND THE LDC HAVE MANY OF THE SAME COMPONENTS AS THE PRODUCER/BROKER AGREEMENTS AND WILL THEREFORE BE OMITTED TO REDUCE REPETITION.

PRODUCER CONTRACTS

INTERPRETATION

WITHIN THE **INTERPRETATION** SECTION OF THE CONTRACT, YOU WILL FIND CLAUSES ON THE DEFINITION OF THE WORDING IN THE AGREEMENT. THINGS LIKE CONTRACT DEMAND (DAILY) VOLUME OF GAS TO FLOW - THE DAY WILL BE DEFINED (8:00 AM TO 8:00 AM) - AS WILL THE GROSS HEATING VALUE, METHOD OF NOMINATING FOR GAS AND THE POINT OF DELIVERY OR ACCEPTANCE OF GAS.

SLIDE 5

THE **CONDITIONS PRECEDENT** SECTION OF THE CONTRACT DEFINES THE CONDITIONS THAT MUST BE SATISFIED BEFORE THE CONTRACT WILL TAKE EFFECT. THIS COULD INCLUDE THE REGULATORY APPROVALS NEEDED TO MOVE THE GAS AND ASSOCIATED

REMOVAL AND TRANSPORTATION AGREEMENTS REQUIRED BEFORE THE CONTRACT WITH THE PRODUCER/BROKER WILL TAKE EFFECT.

SLIDE 6

THE **TERM** SECTION OF THE CONTRACT DEFINES HOW LONG THE AGREEMENT WILL BE FOR AND IS THE START OF THE DECISION MAKING PROCESS IN CONTRACTING.

FOR WHAT PERIOD? - YOU MAY WISH TO TIE THE TERM TO THE COGENERATION PROJECT BUT ONLY IF YOU ARE PARALLEL GENERATING, OR IF YOU REQUIRE ASSURANCES ON PAYBACK OVER A SPECIFIC TIME FRAME.

IF YOU ARE A PARALLEL GENERATOR, THERE MAY BE A MINIMUM CONTRACT LENGTH ENFORCED BY ONTARIO HYDRO AND YOU MAY WANT TO ENSURE A TIE IN OF EQUAL LENGTH WITH YOUR GAS PURCHASE CONTRACT AND YOUR "T" CONTRACTS WITH TCPL AND THE LDC.

THE DAY OF 1ST DELIVERY WILL ALSO BE SPELLED OUT IN THIS SECTION. IT WILL NO DOUBT BE THE DAY ON WHICH GAS FIRST STARTS TO FLOW ON TCPL'S SYSTEM.

SLIDE 7

THE **GAS VOLUME** PORTION OF THE CONTRACT DEFINES THE DAILY CONTRACT QUANTITY OF GAS YOU WILL EXPECT TO BE DELIVERED AND WHETHER COMPRESSOR FUEL IS TO BE SUPPLIED OR NOT. (THIS WILL DEPEND ON THE TYPE OF DIRECT PURCHASE ARRANGEMENT YOU HAVE. BE SURE TO CHECK THIS OUT.)

ARE THERE BACKSTOPPING PROVISIONS - YES/NO?

ENSURE A FIRM GAS SUPPLY; WITH FIRM TRANSPORTATION ON THE NOVA SYSTEM IN SUFFICIENT QUANTITY TO HONOUR THE TERMS OF THE AGREEMENT. THIS HELPS ASSURE THE GAS SUPPLY TO YOUR PLANT IS NOT INTERRUPTED, OR UNABSORBED DEMAND CHARGES ARE NOT INCURRED BECAUSE OF SOMETHING HAPPENING IN WESTERN CANADA.

SLIDE 8

WITHIN THE **PRICE** SECTION OF THE CONTRACT, YOU WILL DISCOVER GAS IS PURCHASED IN ALBERTA IN GJ. CHECK TO ENSURE THE PRICE INCLUDES TOP GAS CHARGES AND AT WHAT SPECIFIC LEVEL. ENSURE IT INCLUDES NOVA "T" SERVICE TO THE SASKATCHEWAN BORDER.

YOU MAY WISH TO CONSIDER GAS PURCHASE PRICE ESCALATORS WHEN CONSIDERING OR NEGOTIATING LONG TERM CONTRACTS. YOU MAY WANT TO CONSIDER PRICE ESCALATING WITH C.P.I.: WITH ONTARIO HYDRO PURCHASE RATES OR SOME COMBINATION OF THE TWO. IF YOU SELECT ESCALATORS, ENSURE YOU TIE THEM TO SOME COMPONENT OF THE PROJECT. APPLES TO APPLES! DON'T TIE THEM TO A COMMODITY THAT IS IN NO WAY ASSOCIATED WITH THE REVENUE OR EXPENSE STREAMS OF THE PROJECT, I.E. PORK BELLIES OR CRUDE OIL.

SLIDE 9

THE **POSSESSION AND TITLE** SECTION OF THE AGREEMENT WILL OBLIGATE THE PRODUCER/BROKER TO ENSURE THE TITLE TO THE GAS IS CLEAR OF LIENS OR CLAIMS AGAINST THE PRODUCT THAT COULD INVOLVE A 3RD PARTY. THIS IS COMMON BOILER PLATE IN ALL GAS CONTRACTS.

SLIDE 10

THE **INVOICING AND PAYMENT PROCEDURES** SECTION WILL COVER DETAILS LIKE HOW IS PAYMENT TO BE MADE, BY BANK TRANSFER OR BY CHEQUE? THESE ARE SMALL THINGS BUT HAVE A SIGNIFICANT LONG TERM IMPACT. IT CAN DETERMINE METHODS OF FUTURE PAYMENT IN THE EVENT OF DEFAULT OR DISPUTE: - DOES GAS CONTINUE TO FLOW?; SPELL IT OUT. WILL THERE BE PENALTIES IN THE EVENT OF LATE PAYMENT? IF SO, THE PENALTY COULD BE STATED IN THIS SECTION.

SLIDE 11

A **DEFAULT SECTION** IN A CONTRACT WILL SPELL OUT WHEN A CONTRACT IS VOIDED. THIS COULD TIE TO DELIVERY AND PAYMENT SECTIONS OF THE AGREEMENT BUT THEN WHAT HAPPENS? BE SURE TO ARRANGE SUFFICIENT TIME TO NEGOTIATE NEW CONTRACTS SO GAS FLOW WILL NOT BE IMPEDED. I HAVE NOT HEARD OF ANYONE FINDING THEMSELVES IN THIS POSITION, BUT YOU WOULD CERTAINLY WANT TO PROTECT YOURSELF FROM THIS EVENTUALITY.

SLIDE 12

THE **FORCE MAJEURE** SECTION OF ANY AGREEMENT WILL DEFINE THE SPECIFIC RESPONSIBILITIES OF BOTH PARTIES IN THE EVENT OF FORCE MAJEURE OF EITHER PARTY. IF FOR REASONS OF EQUIPMENT BREAKDOWN OR OTHER INSTANCES OF FORCE MAJEURE, YOU WILL WANT TO KNOW IF YOU WILL BE RESPONSIBLE FOR ANY FIXED COSTS OF YOUR SUPPLIER. THIS SECTION SHOULD SPELL THEM OUT.

SLIDE 13

YOU MAY WISH TO ADD SECTIONS TO CONTRACTS BECAUSE OF CONTRACTING REQUIREMENTS LIKE **COGENERATION** **CONSIDERATION.** MAINLY BE TO THE BENEFIT OF PARALLEL GENERATORS PLANNING ON GRID AND SELLING EXCESS POWER BACK TO ONTARIO HYDRO.

GOVERNMENTS

REMEMBER YOU ARE PURCHASING GAS IN ANOTHER PROVINCE AND YC CONSIDER HOW FUTURE **GOVERNMENT** TAXES AND ROYALTIES COULD IMP PURCHASE PRICE. YOU MAY WISH TO ATTEMPT TO IDENTIFY THE METH WITH EVENTS NOT CONTEMPLATED AT THIS TIME. HOW WILL TAXES, RC BE PAYED IN FAIRNESS TO BOTH PARTIES.

IT IS KEY TO REMEMBER AS I CONCLUDE THE DISCUSSION ON CONT ENTER INTO WITH PRODUCERS/BROKERS, THAT IN ORDER FOR A CONTRA GOOD CONTRACT, IT MUST BE FAIR TO BOTH PARTIES. STRI AGREEMENTS MAY NOT BE IN YOUR BEST LONG TERM INTERESTS. CIRCU A WAY OF CHANGING OVER TIME AND YOU WANT TO ENSURE FUTURE SA BOTH PLAYERS WHEN ENTERING LONG TERM RELATIONSHIPS.

T.C.P.L. CONTRACTS

SLIDE 14

I STATED IN MY OPENING COMMENTS THAT THERE WOULD BE A LOT OF I COVERED EACH CONTRACT IN DETAIL, SO I WILL SAVE YOU THE PAI

THE SECTION OF AGREEMENTS THAT HAVE ALREADY BEEN COVERED LIKE INTERPRETATION, FORCE MAJEURE AND PRICE (WHICH IS A TOLL ISSUE UNDER THE NEB IN **TCPL AGREEMENTS**).

FIRM SERVICE

ENSURE THAT YOUR CONTRACT IS FOR **FIRM SERVICE** OTHERWISE YOU WILL BE FACED WITH UNABSORBED DEMAND CHARGES ON THE TCPL SYSTEM SINCE YOUR LDC WILL NOT RECEIVE OPERATIONAL DEMAND RELIEF ON THEIR TCPL FIRM CONTRACTS. THIS ISSUE IS NOW BEFORE THE OEB FOR DETERMINATION OF THE CAUSE AND EFFECT RELATIONSHIP.

SHOULD YOU, HOWEVER, DECIDE TO HAVE MORE THAN ONE TYPE OF SERVICE ON TCPL, THEN A SEPARATE CONTRACT WOULD BE REQUIRED FOR EACH TYPE OF SERVICE (**IE. FIRM AND INTERRUPTIBLE**).

SLIDE 15

TERM

TERMS PRESENTLY AVAILABLE FOR TCPL FIRM SERVICE AGREEMENTS ARE FOR 1 TO 3 YEARS. CONTRACTS OF 15 YEARS ARE ALSO AVAILABLE. IF ONTARIO HYDRO REQUIRES A 10 YEAR CONTRACT FOR PARALLEL GENERATORS, SOME NEGOTIATION BETWEEN THE PARTIES IS CALLED FOR. ATTEMPT TO MATCH THE TERMS OF ALL CONTRACTS.

SLIDE 16

BOILER PLATE

AS ALREADY STATED, MUCH OF THE **BOILER PLATE** FOUND IN OTHER AGREEMENTS WILL, IN THE CASE OF TCPL, FORM PART OF THEIR TOLLS (IN OTHER WORDS, IT IS PART OF THE RATES THEY CHARGE FOR MOVING THE GAS). T.C.P.L. WILL WANT TO ENSURE THAT GAS IS AVAILABLE ON A FIRM BASIS AT THE POINT OF INTERCONNECT AT THE ALBERTA SASKATCHEWAN BORDER CLEAR OF LIENS AND ENCUMBRANCES. IT WILL ALSO REQUIRE ASSURANCE THAT YOU HAVE A CONTRACT WITH YOUR LDC FOR AT LEAST THE TERM OF THEIR CONTRACT.

ALSO, ASSURANCE WILL BE REQUIRED THAT THE LDC WILL ULTIMATELY REDELIVER TO YOU ALL OF THE VOLUME TRANSPORTED BY TCPL.

IN ADDITION, ASSURANCE THAT YOU HAVE A REMOVAL PERMIT FROM THE PROVINCE OF PRODUCTION WHICH IS CONSISTENT WITH RESPECT TO QUANTITY AND TERM WILL BE REQUIRED.

PRIOR TO TCPL'S ACCEPTANCE, DON'T BE SURPRISED IF TCPL ASKS FOR INFORMATION DEMONSTRATING ANNUAL CONSUMPTION, AS WELL AS THE TYPE OF SERVICE BEING SUPPLIED BY THE LDC.

LOCAL DISTRIBUTION COMPANY (LDC)

WHEN CONTRACTING WITH YOUR **LDC,** YOU MAY WISH TO EXPLORE THE KINDS OF CONTRACTS THAT ARE AVAILABLE TO YOU. I WON'T SPEAK TO SPECIFIC RATES SCHEDULES, BUT WOULD LIKE TO REVIEW THE TYPES OF CONTRACTS THAT YOU MAY WISH TO CONSIDER IN CONJUNCTION WITH THE COGENERATION EQUIPMENT YOU MAY INSTALL.

SLIDE 17

FIRM CONTRACTS

IF YOU ARE CONTEMPLATING AN ENGINE OR GAS TURBINE YOU WILL PROBABLY WANT TO CONTRACT FOR **FIRM SERVICE**. FIRM SERVICE CONTRACT RATES HAVE A MONTHLY DEMAND CHARGE BASED ON DAILY REQUIREMENTS AND WOULD BE QUITE BENEFICIAL TO A COGENERATOR BECAUSE OF THE HIGH LOAD FACTOR INHERENT IN THIS EQUIPMENT. (IN OTHER WORDS ITS FREQUENT USE EACH DAY WOULD ALLOW THE DEMAND CHARGE TO BE SPREAD OVER THE USE ON A DAILY BASIS OVER THE MONTH RESULTING IN A LOWER PER UNIT RATE FOR THE GAS.)

SLIDE 18

INTERRUPTIBLE CONTRACTS

INTERRUPTIBLE GAS SHOULD ONLY BE CONSIDERED WHEN INSTALLING A STEAM TURBINE USED IN CONJUNCTION WITH A STEAM BOILER PLANT THAT IS DUAL FUELLED. IN THE CASE OF A GAS INTERRUPTION AS ANTICIPATED IN THE CONTRACT, THE BOILER COULD BE SWITCHED TO THE STANDBY FUEL THUS CONTINUING TO GENERATE STEAM AND AN UNINTERRUPTED SOURCE OF ELECTRICITY THROUGH THE STEAM TURBINE.

WITH OTHER TYPES OF COGENERATION EQUIPMENT, IT CAN BE IMPRACTICAL TO ADD PROVISIONS FOR A SECOND FUEL.

SLIDE 19

COMBINATION CONTRACTS ALLOW YOU TO PURCHASE BOTH FIRM AND INTERRUPTIBLE GAS UNDER ONE CONTRACT.

DEPENDING ON YOUR MIX OF GAS CONSUMING APPLIANCES, YOU MAY WISH TO CONTRACT FOR FIRM SUPPLIES FOR TURBINES AND OTHER PROCESS EQUIPMENT WHERE INTERRUPTIONS OF GAS SUPPLY DISRUPT YOUR OPERATIONS. WHERE READILY ACCESSIBLE STANDBY FUEL IS AVAILABLE FOR APPLIANCES THAT ARE DUAL FUELLED, YOU MAY WISH TO CONTRACT FOR INTERRUPTIBLE GAS THEREBY OPTIMIZING ON YOUR ENERGY PURCHASES SINCE INTERRUPTIBLE GAS IS LOWER PRICED THAN FIRM GAS.

SLIDE 20

RATES FOR SERVICE ARE DIFFERENT DEPENDING ON VOLUME, FIRM OR INTERRUPTIBLE, SO WORK WITH YOUR LDC BECAUSE GAS FIRED COGENERATION IS A VERY DESIRABLE LOAD TO THE UTILITY. THE INCREASE OF GAS LOAD ADDED COULD CONCEIVABLY QUALIFY YOU FOR ANOTHER RATE STRUCTURE OR IMPROVE YOUR PRICE WITHIN THE RATE YOU ARE PRESENTLY SERVED UNDER. THESE ARE KEY CONSIDERATIONS WHEN ASSESSING THE ECONOMICS OF A NEW COGENERATION PROJECT. THE PRICE, EITHER "T" OR SALES SERVICE RATES ARE STIPULATED IN THE AGREEMENT AND ARE SUBJECT TO CHANGES APPROVED BY OUR REGULATOR, THE OEB, AFTER THE PUBLIC HEARING PROCESS.

SLIDE 21

VOLUMES

THERE WILL, UNDER CONTRACT RATES, BE MINIMUM **VOLUME** CONSUMPTION LEVELS CONTRACTED FOR ON A TAKE OR PAY BASIS. IF CONTEMPLATING "T" SERVICE THERE MAY OR MAY NOT BE SINCE PERMANENT "T" RATES ARE BEFORE THE OEB NOW AWAITING A DECISION. YOUR LDC WILL, OF COURSE, ADVISE YOU OF THE STATUS OF THESE RATES AS TIME PROGRESSES.

SLIDE 22

DELIVERY PRESSURE

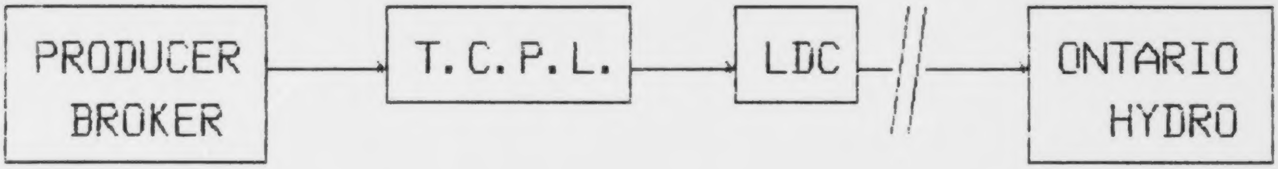
DELIVERY PRESSURE IN THE CONTRACT COULD BE VERY IMPORTANT AND SHOULD BE CONSIDERED IN THE SELECTION OF YOUR COGENERATION EQUIPMENT. THE PROPER CONTRACT DELIVERY PRESSURE COULD ELIMINATE THE NEED FOR COMPRESSORS UPSTREAM OF TURBINES REQUIRING MINIMUM OPERATING PRESSURES.

SLIDE 23

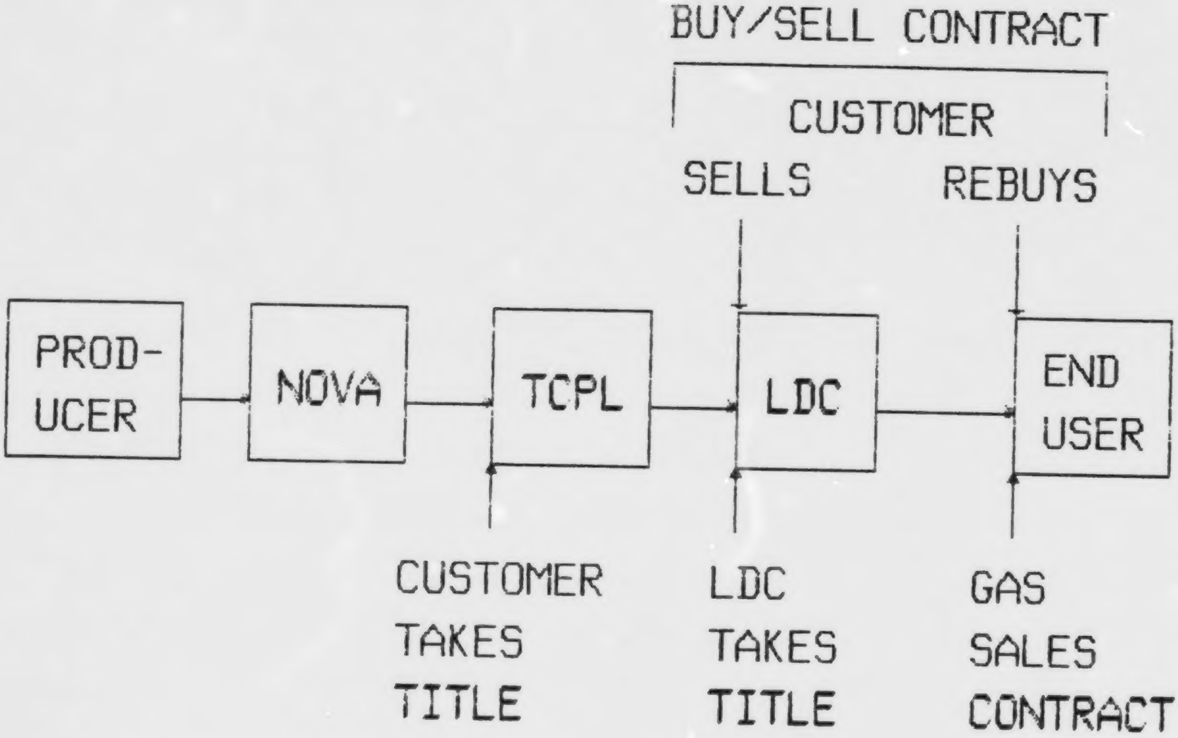
THE **BOILER PLATE** IN LDC CONTRACTS ARE VERY SIMILAR TO THOSE PREVIOUSLY MENTIONED AND INCLUDE INTERPRETATION (WHICH IS ONTARIO JURISDICTION) TRANSFER AND ASSIGNMENTS - PRIORITY OF SERVICE - GAS QUALITY ETC.

CLOSING COMMENTS

REQUIRED CONTRACTS


PRODUCER
BROKER
T.C.P.L.
LDC
ONTARIO
HYDRO

BUY/SELL


BUY/SELL CONTRACT
CUSTOMER
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END USER
CUSTOMER TAKES TITLE
LDC TAKES TITLE
GAS SALES CONTRACT

PRODUCER CONTRACT

. INTERPRETATION

PRODUCER CONTRACT

- INTERPRETATION
- CONDITIONS PRECEDENT

PRODUCER CONTRACT

- INTERPRETATION
- CONDITIONS PRECEDENT
- TERM

PRODUCER CONTRACT

- INTERPRETATION
- CONDITIONS PRECEDENT
- TERM
- GAS VOLUME

PRODUCER CONTRACT

- INTERPRETATION
- CONDITIONS PRECEDENT
- TERM
- GAS VOLUME
- PRICE

PRODUCER CONTRACT

- INTERPRETATION
- CONDITIONS PRECEDENT
- TERM
- GAS VOLUME
- PRICE
- POSSESSION & TITLE

PRODUCER CONTRACT

- INTERPRETATION
- CONDITIONS PRECEDENT
- TERM
- GAS VOLUME
- PRICE
- POSSESSION & TITLE
- INVOICING & PAYMENT

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PRODUCER CONTRACT

- INTERPRETATION
- CONDITIONS PRECEDENT
- TERM
- GAS VOLUME
- PRICE
- POSSESSION & TITLE
- INVOICING & PAYMENT
- DEFAULT

PRODUCER CONTRACT

- INTERPRETATION
- CONDITIONS PRECEDENT
- TERM
- GAS VOLUME
- PRICE
- POSSESSION & TITLE
- INVOICING & PAYMENT
- DEFAULT
- FORCE MAJEURE

PRODUCER CONTRACT

- INTERPRETATION
- CONDITIONS PRECEDENT
- TERM
- GAS VOLUME
- PRICE
- POSSESSION & TITLE
- INVOICING & PAYMENT
- DEFAULT
- FORCE MAJEURE

OTHER CONSIDERATIONS

- COGENERATION
- GOVERNMENT

T.C.P.L. CONTRACT

. FIRM SERVICE

T.C.P.L. CONTRACT

- FIRM SERVICE
- TERM

T.C.P.L. CONTRACT

- FIRM SERVICE
- TERM
- BOILER PLATE

LDC CONTRACT

- FIRM CONTRACT

LDC CONTRACT

- FIRM CONTRACT
- INTERRUPTIBLE

LDC CONTRACT

- FIRM CONTRACT
- INTERRUPTIBLE
- COMBINATION

LDC CONTRACT

- FIRM CONTRACT
- INTERRUPTIBLE
- COMBINATION
- RATES

LDC CONTRACT

- FIRM CONTRACT
- INTERRUPTIBLE
- COMBINATION
- RATES
- VOLUMES

LDC CONTRACT

- FIRM CONTRACT
- INTERRUPTIBLE
- COMBINATION
- RATES
- VOLUMES
- DELIVERY PRESSURE

LDC CONTRACT

- FIRM CONTRACT
- INTERRUPTIBLE
- COMBINATION
- RATES
- VOLUMES
- DELIVERY PRESSURE
- BOILER PLATE

Closing Remarks

By
W. Weinstein, P.Eng.
Consulting Engineers of Ontario

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CO-GENERATION SEMINAR

CARA INN, TORONTO

MARCH 10, 1988

CLOSING REMARKS
W. WEINSTEIN, P.ENG.
EXECUTIVE DIRECTOR
CONSULTING ENGINEERS OF ONTARIO

I AM PLEASED AS A REPRESENTATIVE OF THE ASSOCIATION OF CONSULTING ENGINEERS OF ONTARIO, A CO-SPONSOR OF THIS SEMINAR, TO CONGRATULATE THE ORGANIZING COMMITTEE FOR THEIR SUPERB EFFORTS IN PRODUCING SUCH A FINE PROGRAM. THE SPEAKERS WERE WELL CHOSEN FOR THEIR ELOQUENCE AND EXPERTISE AND DESERVE OUR APPRECIATION FOR THEIR WILLINGNESS TO SHARE SUCH STATE OF THE ART KNOWLEDGE EXPERIENCED INTERNATIONALLY.

THE LARGE ATTENDANCE CONFIRMS THE BROAD INTEREST IN THE SUBJECT WHICH WAS DISCUSSED IN SPIRITED DEBATE WITH THE SPEAKERS REPRESENTING EQUIPMENT MANUFACTURERS, CONSULTING ENGINEERS, NATURAL GAS RELATED INDUSTRIES, ONTARIO HYDRO AND THE MINISTRY OF ENERGY.

IT IS FITTING THAT THIS EVENT WAS HELD DURING ENGINEERING WEEK CURRENTLY BEING PROCLAIMED IN METROPOLITAN TORONTO, A FUNCTION ALSO CO-SPONSORED BY CEO IN CONJUNCTION WITH THE EIC. THE OCCASION PROVIDES AN OPPORTUNITY FOR THE PUBLIC AT LARGE TO RECOGNIZE THE ACHIEVEMENTS OF A DEDICATED PROFESSION THAT IS INVOLVED IN ALL OF MANKINDS ENDEAVORS WHICH IMPROVE OUR QUALITY OF LIFE.

THOSE OF YOU ASSEMBLED HERE TODAY ARE TO BE THANKED FOR YOUR TECHNICAL CONTRIBUTIONS, MADE AND TO BE MADE, FOR THE WELFARE OF SOCIETY.

UPPER CANADA, THE ONTARIO OF TODAY, WAS SEEN AS A SPARSELY POPULATED WILDERNESS BY ITS SETTLERS WHO CONFRONTED THE RIGORS OF CLIMATE AND TOPOGRAPHY TO FASHION A NEW NATION. THE GROWTH OF OUR PROVINCE WAS MADE POSSIBLE BY THE ENGINEER WHO APPLIED TECHNOLOGY TO THE NEEDS OF PEOPLE, OFTEN BUILDING ON THE SELF-TAUGHT SKILLS OF THE PIONEER. THE NEEDS WERE MET WITH LINKS TO CENTERS OF POPULATION VIA ROADS, RIVERS, AND THE SEA. NAVIGATION WAS FACILITATED BY CANALS WITH THEIR VELOCITY TAMING LOCKS. RAILWAYS LINKED THE COUNTRY TOGETHER. URBAN CENTERS EXPANDED AND THE PROBLEMS OF WATER SUPPLY AND SEWAGE TREATMENT WERE RESOLVED.

ENGINEERS, HOWEVER, WERE PRESENTED WITH PERHAPS THEIR GREATEST CHALLENGE, POWER AND ENERGY, BASIC ELEMENTS IN THE HEALTH AND GROWTH OF OUR SOCIETY AND A DIFFICULTY WE STILL FACE TODAY - IN SPADES. OUR FIRST SOURCE OF POWER, ABOVE THE MIGHT AND SINEWS OF OUR POPULOUS AND ANIMALS, WAS POWER DERIVED FROM WATER. WOODEN WATER WHEELS DREW POWER FROM OUR RIVERS BUT EVEN SUCH INGENIOUS DEVELOPMENT FELL SHORT OF OUR

......3

NEEDS. FOR MORE POWER AND POWER WHEN WE WANTED IT, WE BUILT HUGE DAMS WHICH CONTRIBUTED TO FLOOD CONTROL AND AGRICULTURAL IRRIGATION, TO RECREATIONAL FACILITIES AND TO DOMESTIC WATER NEEDS. WE DELVED DEEPER AND DEEPER INTO THE EARTH, MINING THE ORES AND COAL NEEDED FOR OUR INCREASING TECHNOLOGY. ORES WHICH GAVE US METALS WITH EXOTIC QUALITIES AND OPENED NEW POTENTIALS IN METALLURGY. THE DEVELOPMENT OF ANOTHER FOSSIL FUEL AND ACCOMPANYING NATURAL GAS EXTRACTED FROM CANADA'S FIRST OIL FIELD IN PETROLIA, ONTARIO ADDED NEW DIMENSIONS TO OUR ENERGY RESOURCES AND OPENED NEW VISTAS TO THE EXCITING APPLICATIONS OF PETROCHEMICALS.

NOW WE ARE FACING THE CHALLENGING ENGINEERING PROBLEMS ASSOCIATED WITH PROVIDING POWER FROM THE ATOM ITSELF, STRAINING OUR SKILLS TO THE UTMOST TO MEET THE EXACTING CONDITIONS OF WORKING WITH NEW MATERIALS AND NEW TECHNIQUES. OUR CHALLENGE IS TO SATISFY SOCIETY OF THE RELIABILITY OF CANDU TECHNOLOGY IN LIGHT OF THE MAGNITUDE OF RECENT EXPERIENCES AT 3 MILE ISLAND AND CHERNOBYL. OTHER ENERGY SOURCES SUCH AS WOOD, MUNICIPAL SOLID WASTE, SOLAR ENERGY OR WIND ARE MEETING A SMALL DEMAND IN ONTARIO.

ONTARIO'S PROSPERITY HAS BEEN BUOYANT LARGELY DUE TO ITS ABUNDANT RELIABLE ECONOMICAL ENERGY SUPPLY.

....4

OUR SOCIETY IS BEING CONDITIONED TO PROTECT ITS SCARCE RESOURCES AND ENERGY CONSERVATION WILL AT LEAST EXTEND SUCH TREASURES. THERE WILL BE A DAY OF RECKONING, HOWEVER, AND OUR ENERGY LINE OF CREDIT WILL BE IMPINGED UPON. WE MUST THEREFORE DRAW UPON THE SOURCE ENGINEERS HAVE MOBILIZED THROUGHOUT HISTORY -CONDITIONED INTELLECT - BECAUSE AS WE POSTULATE - 'KNOWLEDGE IS POWER'.

YOU HAVE BEEN PART OF AN EDUCATIONAL EXPERIENCE TODAY WHICH WILL ENDOW YOU WITH KNOWLEDGE WHICH IF APPLIED APPROPRIATELY WILL CONTRIBUTE IN A SMALL WAY TO POWER OUR ECONOMIC ENGINE TO SUCCESSFULLY FACE THE WORLD MARKETPLACE.

IN ORDER FOR ONTARIO TO REMAIN COMPETITIVE, EFFICIENT UTILIZATION OF POWER GENERATING RESOURCES IS MANDATORY. THIS PRESENTS A CHALLENGE AND A RESPONSIBILITY TO ENGINEERS, MANUFACTURERS, UTILITIES AND GOVERNMENT. CO-GENERATION IS A DEVELOPED TECHNOLOGY WHICH IS ONE OF THE OPTIONS FOR MEETING THIS CHALLENGE. I AM CONFIDENT THAT YOUR DELIBERATIONS TODAY WILL BETTER ENABLE YOU TO EVALUATE THIS ALTERNATIVE TECHNOLOGY.

........5

AS MANY OF YOU ALREADY KNOW OUR ASSOCIATION HAS A SLOGAN. IT STATES "ONTARIO IS GREAT BECAUSE IT WAS ENGINEERED THAT WAY" THINGS DON'T JUST HAPPEN.....WE MAKE THEM HAPPEN. I URGE YOU TO TO CONTINUE IN YOUR EFFORTS TO MAKE ONTARIO EVEN GREATER.

THANK YOU!

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